FortisBC Inc.
AMI Project **Exhibit** B-3

FORTISBC

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March 19, 2008

Via Email
Original via mail

Ms. Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: An Application for a Certificate of Public Convenience and Necessity for the Advanced Metering Infrastructure Project No. 3698493

Please find enclosed FortisBC Inc's Responses to Information Requests No. 2 from the BC Utilities Commission, BCOAPO et al., Mr. Alan Wait, Mr. Hans Karow, and Horizon Technologies. Twenty copies will be couriered to the Commission.

Sincerely,

David Bennett
Vice President, Regulatory Affairs
and General Counsel

cc: Registered Intervenors

1.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q3.1, p. 4

Customers Served

Q1.1 In response to OTR BCUC IR No. 1 Q3.2, approximately 34,000 customers are not included in the AMI program. Would FortisBC explain who these customers are, the Annual kWh used by these customers when compared to those that are proposed to be on AMI, when these customers will be converted to AMI and the estimate of additional incremental cost to the current AMI program be considered?

A1.1 The table in OTR BCUC IR No. 1 Q3.2 (Exhibit B-3) refers to indirect customers located in the Okanagan area, served by the City of Kelowna, City of Penticton, and District of Summerland. The total number of indirect customers in FortisBC's service area includes those served by the City of Grand Forks, City of Nelson, and BC Hydro's customers in Yahk and Lardeau, and is approximately 46,000. FortisBC does not have data on annual use per indirect customer, but would expect indirect customers' characteristics to be approximately the same as direct customers'.

As these customers are served by other utilities, FortisBC is not proposing to include them in the AMI Project. FortisBC would welcome discussions regarding possible agreements with the municipal utilities to extend the AMI system to those 46,000 customers.

A shared infrastructure would add both operating and capital cost, but without contractual agreements, the specifics of these costs cannot be determined.

Q1.2 Have the municipalities within your service area consider AMI technology?

A1.2 Please refer to the response to BCOAPO IR No. 1 Q11.1 (Exhibit B-2).

Q1.3 Has FortisBC had any discussions with the municipalities within their service area regarding the implementation of AMI technology and new rate structures?

A1.3 FortisBC contacted the municipal customers listed in the response to BCUC IR No. 2 Q1.1 prior to filing the Application, and provided them an opportunity to discuss FortisBC's AMI implementation. None of the municipal customers identified any concerns over the implementation of FortisBC's AMI technology.

Q1.4 What would be the additional cost savings to FortisBC, if any, of adding the additional 34,000 customer to the AMI program?

A1.4 As FortisBC does not read the meters of the indirect customers today, there would be no cost savings associated with adding the additional indirect customers to the AMI program. There may, depending on the terms of any contracts with municipal customers, be incremental revenues associated with the additional customers.

Q1.5 Would FortisBC be able to read all the municipal meters within this service area and then provide the billing information back to the various municipalities or would the municipalities install their own AMI systems?

A1.5 Please refer to the response to BCUC IR No. 2 Q1.1. If FortisBC were to take readings on behalf of the municipal utilities, system interfaces to their respective billing systems would be required to support the transmission of meter read data back to them. Additional AMI communications infrastructure may also be required, depending on the technology chosen and the location and configuration of the utilities' customer bases.

2.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q4.1, p. 5
Existing Meter Rate Capability

Q2.1 As the existing meters can handle flat rates and simple block rates, would FortisBC please confirm if their existing meters would be able to handle a two step inclined block rate?

A2.1 Confirmed. Existing meters can handle a two step inclined block rate since this type of rate requires total consumption for billing. However, any meter reading estimates used to calculate bills (for residential customers receiving bi-monthly billings, for example), are potentially controversial since any billing at higher block rates would be estimated.

3.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q5.1, p. 5

Project Need

Q3.1 Please provide a response to the question that outlines specific trends / changes in the costs of AMI technologies in recent years.

A3.1 In its response to BCUC IR No. 1 Q5.1, p. 5 (Exhibit B-2), FortisBC was specifically referring to the cost of remote-reading endpoints. FortisBC currently purchases a small number of electronic meters with basic AMR “drive-by” reading functionality for installation in difficult-to-access locations. Recent costs for these AMR-capable meters are between $75 and $109 per meter, which is comparable to the range of costs expected for AMI-capable meters.

With respect to cost of AMI systems as a whole, there are two major developments that, in the opinion of FortisBC, are serving to create a slight downward pressure on costs.

The first development relates to the availability of wireless mesh technology in the wireless AMI market. Though not suited for all markets, this technology uses neighbouring electric meters as repeaters instead of employing the traditional point to point communications method that requires the use of pole top data collectors to store and forward meter data to the utility data center. Please refer to page 45 from the AMI CPCN Application (Exhibit B-1) for a diagram illustrating mesh and tower technologies. These technologies have done away with the traditional communications topology and eliminated the multi-tiered communications hierarchy associated with use of pole top collectors and concentrators. This in turn has reduced overall network cost.

The general growth in AMI deployment activity is the second development producing downward pressure on costs. The increased production volumes related to the increase in activity have yielded manufacturing savings through economies of scale and made it more cost effective to move manufacturing operations off-shore. The cost reductions realized though increased volume are expected to be offset to some degree in the near term by a relatively tight supply of AMI products relative to demand.

Q3.2 Why are cost reductions not likely to continue in the near future?

A3.2 As stated in the response to BCUC IR No. 2 Q3.1, the tight supply of AMI products is balancing the cost reductions that naturally occur from increased production volumes. As well, technical designs have stabilized for many AMI systems, and as most major meter manufactures are now producing solid state residential meters, the AMI endpoint market is exhibiting some price stability. Prices for copper and other commodities have continued to rise, and many recent orders have been large volume purchases that drive down component prices to their lowest possible levels.

4.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q6.1, p. 6
Existing Meter Rate Capability and
Exhibit No. B-2, FortisBC Response to BCUC Q38.1, p. 97
Project Costs

FortisBC states: "It will be a requirement that the AMI system is capable of collecting gas and water meter readings. FortisBC would consider allowing utilities interested in collecting gas and water meter readings using the AMI infrastructure to do so, provided they contribute any required incremental capital costs and pay a usage fee."

Q4.1 What is the incremental cost of including the capability of gas and water meter readings immediately?

A4.1 For most AMI technologies (RF in particular), there is no additional capital cost since the meter is already equipped with an RF module capable of communicating with gas and water meters.

For some AMI technologies (PLC in particular), the capital cost of including a module that can communicate directly with gas and water meters is approximately $30 per meter. This is the cost of installing an RF communications module into the AMI meter that would be able to read the gas and / or water meter on the same premise.

In order for FortisBC to include any incremental capital costs that would enable the AMI system at the time of implementation to communicate directly with gas and water meters, FortisBC would first require agreements with other utilities that would make such additional capital expenditures economic and ensure that FortisBC customers bear none of the related costs.

Regardless of whether additional capital is required to enable the AMI system to communicate directly with gas and water meters, additional capital expenditures will be required to pay for the gas and water meters, any additional communications or IT infrastructure, and additional operating expenses. How these costs would be recovered from gas and water utilities would be the subject of future contract negotiations, but could include capital contributions and usage fees.

Q4.2 To whom would FortisBC offer the capability of reading gas and water meters?

A4.2 FortisBC would offer gas and water meter reading to all entities providing metered gas and water services within its service territory boundaries.

Q4.3 Has Fortis BC had discussions with other utilities on using those features? What is the level of interest and likelihood FortisBC would be able to leverage those capabilities?

A4.3 FortisBC has not discussed this possibility with any utilities other than Terasen Gas Inc. which indicated a general interest, as stated in its letter to the Commission of February 8, 2008 (Exhibit D-2). FortisBC did offer to provide information regarding this Application to its wholesale customers, with limited response from those customers. FortisBC is willing to provide these features and services under the general terms outlined in the response to BCUC IR No. 2 Q4.1.

Q4.4 Would all revenues collected from leveraging such capabilities be to the benefit of customers? Please discuss this in the context of the current approach to rate setting.

A4.4 Yes. The revenues are forecast annually and would be an offset to revenue requirements. It is expected that since any arrangements of this nature would be contractual, variances from forecast would be small. However, under FortisBC's current PBR mechanism, all variances that impact earnings are equally shared with customers on an after-tax basis.

Q4.5 What is the maximum number of electrical meters that the AMI system is capable of reading?

A4.5 The AMI system is required to be scalable to read a minimum of one million electrical meters.

Q4.6 What percentage of the specified AMI capability would be dedicated to electric, gas, and water meter reading?

A4.6 The AMI capability planned within the scope of this Project is dedicated to the electric meter and FortisBC's direct customers. The capability of reading gas and water meters comes from using the communications module within the electric meter to pass readings to the communications infrastructure. The functions for gas and water meter reading would be limited to the reading of meters and transmitting of data only.

Q4.7 If the specified system is compatible with reading gas and water meters, what is the number of gas and water meters specified?

A4.7 FortisBC's RFP requirement will be that the system be able to accommodate a minimum of one gas and one water meter (in addition to the electrical meter) at each metered service point (included in the scope of the Project) in the Company's service territory.

Q4.8 What is the estimated future cost of including about an additional 100,000 gas and water meters into the FortisBC AMI?

A4.8 If the AMI technology chosen required additional capital expenditures to communicate with gas and water meters, any incremental costs for the core AMI system (which are dependent on the technology chosen, as described in response to BCUC IR No. 2 Q4.1) could be incurred after AMI implementation or be absorbed in the initial deployment.

If the additional capital expenditures were required and incurred after initial deployment, the affected meters would need to be removed, modified, re-sealed and re-installed at a cost of approximately $295 per meter (including the cost of the RF module).

If the additional capital expenditures were required and incurred during the initial deployment, the cost would be approximately $30 per meter, depending on the technology chosen.

Whether or not additional capital expenditures were required to communicate with gas and water meters, enhancements would be required to the MDMR system to permit FortisBC to collect the readings and forward them to the respective utilities. The cost of this enhancement would depend on the specific data requirements of the utilities but a basic system would not be expected to exceed $250,000. All contractual agreements entered into between FortisBC and other utilities for such services would ensure that FortisBC customers do not bear any cost for providing the service.

5.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q6.6, p. 8

Line Losses

"An AMI implementation, in conjunction with the Distribution Substation Automation Program, would allow a feeder-by-feeder analysis of actual distribution line losses. Once identified, a corrective action would have to be undertaken to actually reduce the loss. It is unknown at this point how much line loss savings could be realized as a result of this analysis. Therefore, no line loss savings have been identified."

Q5.1 When FortisBC identifies the corrective action to be undertaken, would FortisBC please provide the loss savings identified to the Commission as a result of the Distribution Substation Automation Program and the AMI if approved?

A5.1 Once the substation is equipped with power quality metering equipment and all downstream delivery points equipped with AMI meters, it will be possible to quantify distribution system losses for a feeder or substation. Thereafter, loss reductions associated with a system upgrade or reconfiguration could be quantified. FortisBC, at this time, has not determined the parameters or timeframe to undertake such analyses with a view to reducing system losses, but agrees to provide an annual report on any such system improvements.

6.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q7, p. 10

Project Description

Q6.1 FortisBC discusses the estimated $142k per year required for two additional IT resources for ongoing maintenance of communication infrastructure. Where exactly are these additional resources reflected in the Revenue Requirements Analysis and the DCF Analysis for the project?

A6.1 These costs are included in the Revenue Requirements Analysis within the costs on line 32. In the DCF analysis, the costs are included on line 16, which is labeled “Customer Service”.

7.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q7.1, p. 11

IT Resources

Q7.1 As robust and trouble free communications are required to permit the AMI program to be successful, would FortisBC please reconsider its requirement for a full-time IT resource allocated to troubleshoot communications issues?

A7.1 The operational needs of the AMI system are based on the expectation of a robust and trouble free communications system. This full-time IT resource will, in addition to troubleshooting communications issues, perform required maintenance and monitor and reconfigure the network as required to accommodate customer growth and/or other system changes. Given the number of communications devices that will be installed in the field (more than 108,000), the distance across, layout and terrain of FortisBC's service territory, FortisBC believes that the system could not be adequately maintained with less than one full-time IT resource.

Q7.2 What is the expected unattended "UP" time and are there any negative impacts?

A7.2 FortisBC does not consider the issue of "unattended up time" to be of concern. The read success rate for AMI systems is very high, normally 98 percent or higher, for the network servers and the associated equipment that runs the system. The distributed nature of an AMI system generally precludes it from experiencing significant down time even during storm conditions, and solid state smart meters typically have on board data storage capacity in the 30-60 day range, depending on the size of the data intervals. FortisBC will require the system to re-transmit data stored in meters and data collectors so that critical meter reading and operations data is recovered. In addition, since the system will be regularly monitored by a full-time IT resource as described in response to BCUC IR No. 2 Q7.1 above, significant delays in identifying communications issues are not expected.

Q7.3 What are the expected Mean Time Before Failure, and Mean Time Before Repair of the communications systems by type for the AMI proposal and are there any negative impacts?

A7.3 AMI systems are a mix of technologies supplied by a variety of vendors, including meter manufacturers, AMI vendors supplying the LAN communications infrastructure, companies supplying the WAN hardware and software suppliers. The reliability of each of these components, and the specific manner in which they are implemented, impacts the reliability of the system.

FortisBC expects to specify the reliability requirements by requiring a 98 percent read success rate for the AMI system. The RFP will also specify warranty provisions to help ensure compliance with this requirement and to help ensure the maintenance costs of the system do not exceed those specified in this Application.

8.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q9.0, p. 12
DSM, Annual Peak Demand or Energy, Load Control

Q8.1 Would FortisBC please confirm that AMI could not be identified as producing positive tangible results for the following programs - DSM, Annual Peak Demand or Energy, Load Control?

A8.1 The response to BCUC IR No. 1 Q9.0 (Exhibit B-2) related to providing tangible results from other utilities using AMI to support DSM programs. Theoretically, FortisBC believes that AMI will support and provide future benefits in the DSM area, however, this is difficult to quantify since the Company is not aware of any utilities reporting tangible results. Since most deployments are multi-year efforts, utilities haven't fully implemented these types of programs yet. Some utilities, including Pacific Gas & Electric, Southern California Edison and PacifiCorp, are projecting significant full system load control savings, but their AMI systems are not yet fully deployed.

FortisBC has included three documents as appendices outlining some of the possibilities of demand response programs that could be developed post AMI implementation.

- NARUC/FERC Collaborative on Demand Response – Appendix 8.1a
- Quantifying Demand Response Benefits – The Brattle Group – Appendix 8.1b
- Ontario Energy Board Smart Price Pilot – Appendix 8.1c
- Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: Report to US Congress – Appendix 8.1d

9.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q15.4.3, Appendix 15.4.3a and 15.4.3b

Project Costs

Q9.1 FortisAlberta's AMI Phase II Business Case states on Page 22: "Many North American utilities are proposing AMI implementations within their territories; as the number of deployments increase, access to vendors and equipment become scarce, and continue to become scarcer, placing upward pressure on costs". Please comment on whether there would be benefit (in terms of access to vendors and equipment, and equipment costs) to waiting until after the significant deployments of AMI in Alberta, Ontario and other jurisdictions during the 2008-2010 time period has been completed.

A9.1 While it is true that a number of utilities, including those involved in the Ontario Smart Metering Initiative, are moving forward with AMI implementation, there is no evidence that this trend is creating significant upward pressure on prices. In fact, it appears that the opposite is true. Most of the major meter manufacturers, for example, have announced expanded manufacturing capacity to accommodate what has been an ongoing growth trend over the past 2-3 years. In the past few years, GE, Elster, Landis+Gyr, Sensus and Itron have all developed residential solid state meters that are commercially available today. This appears to have actually created some downward pricing pressure due to the increased competition and economies of scale.

Given that most AMI installations are multi-year projects, utilities require time to integrate AMI with their other systems and develop new applications such as time based rates. It is important that utilities begin AMI implementation as soon as possible in order to capture the operating and customer service benefits at the earliest opportunity. Utility operating costs, particularly labor and transportation-related costs, are continuing to increase while the favorable US exchange rate is currently having a positive impact on the cost of AMI systems for Canadian utilities.

The Ontario and Alberta deployments, although large in scale in terms of Canadian utilities, only represent a small percentage of the North American AMI market that the AMI vendors are currently servicing. FortisBC believes that there will be sufficient support from these vendors for a successful implementation of AMI and does not believe that there is any benefit to waiting for Alberta and Ontario to complete their deployments.

Q9.2 Please confirm that the FortisAlberta Business Case relies on a DCF analysis of the project, in conjunction with a rate impact analysis. Please confirm the business case analysis by FortisAlberta used a 20-year timeframe.

A9.2 Confirmed.

Q9.3 Please confirm that the Net Present Value of the Phase II AMI Deployment prepared for the 2008/09 Application is about $8 million less than the original estimate in the 2006/07 Application. Please confirm capital cost estimates for full implementation of AMR in Alberta increased from ~$88 million in the 2006/07 Application to ~$104 million in the 2008/09 Application.

A9.3 FortisBC has confirmed that the $104 million referenced above includes the allocation of Engineering and Supervision overhead costs, which were not included in the initial costs. In addition, the 2006/2007 costs were estimated while the FortisAlberta 2008/2009 costs were based on experience garnered from the actual implementation of 26,000 AMI sites.

Q9.4 FortisAlberta is proposing to move from a bi-monthly billing cycle to a monthly billing cycle following introduction of AMI. Please confirm the current billing cycle for FortisAlberta is predominantly bi-monthly for residential customers and monthly for most other customer classes. Please indicate whether there is any intention to change the billing cycle for residential customers following implementation of AMI and whether the costs/benefits of those changes, if any, are reflected in the current analysis.

A9.4 The majority of residential customers are billed monthly but read bi-monthly. This results in a significant number of estimated bills. With the implementation of AMI, FortisAlberta expects to continue on a monthly billing cycle, however these monthly bills will rely on actual reads provided by the AMI rather than the current practice of utilizing estimated reads to fulfill a monthly billing cycle.

FortisBC feels that it will be beneficial in the future to move to a monthly billing cycle based on actual readings for the following reasons:

- **Energy Conservation Awareness:** For those customers that do not have access to (or choose not to view) the near real-time data available to them through the AMI system, monthly billing provides more immediate feedback on consumption than the current bi-monthly billing received by most residential and many commercial customers. As discovered in the Ontario time-of-use pilot studies, this is particularly important for those customers on time-based rates.

- **Resolution of High Bill Complaints:** Customers that experience a higher than expected bill will be alerted to their level of consumption earlier which will allow them time to change their behaviors before the next bill arrives.
- **Lower Bills in the Peak Periods:** For bi-monthly billed customers who have electric heat, winter season bills can sometimes be very high in comparison to electrical consumption throughout the rest of the year. More frequent billing would reduce the amount due for individual months making it less of a financial hardship to the customer.

With and without the implementation of AMI, the estimated annual incremental cost of monthly readings is estimated as follows:

Note that approximately 95 percent of FortisBC's direct customers are currently on bi-monthly billing rates.

Table A9.4: Annual Costs of Monthly Billing ($000s)

	Cost (Savings) Without AMI	Cost (Savings) With AMI	Variance
Meter Reading and Customer Service Costs	1,943	$0	(1,943)
Printing, Postage and Payment Processing Costs	460	460	0
Net Savings (Cost)	**2,403**	**460**	**(1,943)**

The savings and costs associated with monthly billing have not been reflected in NPV Revenue Requirements application because FortisBC does not currently read all meters monthly. If the assumption were made that FortisBC will be moving to monthly readings in 2011 without the implementation of AMI, this would bring the NPV revenue requirements analysis to a payback period of 3 years and a NPV rate impact of -0.95 percent.

Q9.5 Please create a comparison of the total capital costs per meter by sub-category (e.g., meters costs, hardware, installation) from Table 3.3 in the FortisAlberta AMI Phase II – Full Deployment Business Case with the equivalent per meter costs in FortisBC's AMI Application. Please discuss key derivers for any differences in the unit costs for different cost categories in each application.

A9.5 Please see Table A9.5 below:

Table A9.5: Cost per Meter by Category Comparison

		FortisBC CPCN	FortisAlberta Full Implementation	Variance
		$		
Meters and Modules	a	180	187	7
Network Infrastructure	b	62	45	(17)
IT Infrastructure and Upgrades	c	14	2	(12)
Project Management	d	25	6	(19)
AFUDC / Engineering & Supervision	e	9	18	9
Total Cost Per Meter		**290**	**258**	**(32)**

The categories used by FortisAlberta were not the same as used by FortisBC resulting in the discrepancies noted below.

(a) FortisAlberta cost includes some substation/network infrastructure implementation costs;

(b) Installation costs for the network infrastructure is partially embedded with Meters and Module costs within FortisAlberta's costs;

(c) FortisAlberta selected Hunt Technologies and the cost of the MDMR application is included as part of the Meters and Modules;

(d) Hunt Technologies have embedded their project management costs as part of FortisAlberta's Meters and Modules category; and

(e) Engineering and Supervision costs have been included for FortisAlberta above, FortisBC included AFUDC and capitalized overhead costs.

Q9.6 Please create a comparison of the total incremental operating costs and offsets per meter from Table 6.3 in the FortisAlberta AMI Phase II – Full Deployment Business Case with the equivalent per meter costs in FortisBC's AMI Application. Please discuss key derivers for any differences in the unit costs for different cost categories in each application.

A9.6 FortisBC has on a best effort basis completed Table A9.6 below.

Table A9.6: Comparison of Table 6.3 in FortisAlberta Application

Description	FortisAlberta AMI	FortisBC AMI
	$	
Capital Expenditures		
Capital Expenditures	252	290
Capital Offsets	(12)	0 (1)
Corporate E&S	18	N/A
Net Capital Expenditures	**258**	**290**
Operating Expense		
Operating Expense	0.10	0.36
Operating Offsets (Savings)	(0.03)	(0.24)
Net Operating Expense	**0.07**	**0.12**

Notes:
[1]This category reflects the savings with avoided Itron upgrades of ($12 per meter) offset by the incremental costs of new meters over the life of the project of $12 per meter.

There are a number of possible reasons for variances in costs between utilities that were listed in the response to BCUC IR No. 1 Q15.2 (Exhibit B-2) that cannot be quantified. For example, there is no way to determine how much impact if any, the terrain of FortisBC's service area versus FortisAlberta's had an impact on cost. A number of reasons for identified differences are listed in the response to BCUC IR No. 2 Q9.5.

Q9.7 See the cost assumption sheets at the end of Appendix 15.4.3b. Please confirm FortisAlberta assumes an escalation rate of 4.5% for internal labour post 2005 and a general inflation rate of 2.5% (implying a real escalation in labour of 2%). Please confirm that that FortisAlberta did not apply higher rates of escalation (over and above general inflation) to vehicle costs in its analysis. Please contrast these assumptions with the assumptions made by FortisBC.

A9.7 Confirmed. FortisAlberta did not apply a higher rate than 2.5 percent to vehicle costs. FortisAlberta outsources meter reading and therefore has escalated these costs by general inflationary costs. Had meter reading costs been internal, FortisAlberta indicates that these costs would have been escalated at 5.5 percent.

As FortisBC's meter reading staff is internal and not outsourced, there is no contracted protection against the inflation rates of vehicles and their operation. Therefore, as outlined in the response to BCUC IR No. 1 Q27.3 (Exhibit B-2), the BC CPI figure of 5 percent is comprised of a seven year average (2000-2006) of the motor gasoline and transportation components of the BC Consumer Price Index.

10.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q12.0, p. 14-27 Project Costs

Q10.1 Please provide a version of the DCF model (with any changes arising from this set of IRs) that is not password protected, or provide the Commission with the password.

A10.1 An electronic copy of the requested model has been filed in confidence with the Commission.

Q10.2 Please include the capability to switch between a 20-year analysis (as used on the FortisAlberta Applications) and a 25-year analysis (as currently used by FortisAlberta).

A10.2 An electronic copy of the requested model has been filed in confidence with the Commission.

11.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q12.0, p. 14-27

Project Costs

FortisBC states: "Furthermore, the Company is of the opinion that the correct cash flow for project evaluations is the incremental cash flow required from customers in the form of revenue requirements (the ratepayer impact analysis) not the incremental cash flow to the Company resulting from a particular project (the economic impact analysis)."

Q11.1 Please confirm the business cases prepared by FortisAlberta relied heavily on a discounted cashflow (DCF) analysis (incremental cashflow).

A11.1 The business case prepared by FortisAlberta relied on an analysis of the project on both an incremental revenue requirements basis and an incremental cash flow basis.

Q11.2 Please explain in this particular case the major reasons for any differences in the results of the DCF analysis versus the ratepayer impact analysis.

A11.2 The fundamental reason for differences in this case (and any revenue requirement versus cash flow analysis) is that the revenue requirement analysis includes non cash items such as depreciation as well as the cost of financing the project that provides an estimate of the customer rate impact. A discounted cash flow analysis is designed to determine whether a particular course of action will result in a return on investment that is greater than the entity's required return on capital, without regard to customer rate impact.

Q11.3 Please confirm the ratepayer impact analysis relied on a 25-year evaluation period and the AMI capital is fully depreciated over 25 years.

A11.3 Confirmed. The ratepayer impact analysis used a 25 year evaluation period and the AMI capital investment is fully depreciated in year 25.

Q11.4 Please comment on whether or not the Company is of the opinion that depreciation schedules only have customers' impacts, and whether or not project selection should be dependent on accounting principles that determine depreciation schedules?

A11.4 Depreciation expense impacts both customers and the Company. Customers are impacted in that depreciation expense is included in the rates while the Company is impacted by the corresponding reduction in rate base associated with accumulated depreciation.

Although the impact of depreciation on customer rates should be considered in project evaluation, this should not be the sole criteria for project selection.

Q11.5 Please also comment on whether or not incremental cash flow can have both Company and customer impacts?

A11.5 Incremental cash flow can have an impact on both customers and the Company by its impact on working capital and the associated financing costs.

Q11.6 Please also identify an incremental cash flow of the AMI Project that might impact the Company but not customers during the 25-year investment horizon of the AMI Project?

A11.6 The Company does not believe that there is an incremental cash flow associated with the AMI Project that will not impact both the Company and customers.

12.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q12.0, p. 14-27

Project Costs

Q12.1 Please confirm that in the base case real dollar analysis, FortisAlberta assumed 0% escalation of labour and vehicle costs. Please explain why the Company considers this appropriate given the company assumes these line items will escalate above the rate of general inflation and normal practice in real dollar analyses is to include real escalation, where appropriate (e.g., if general inflation is 2% and vehicle cots are assumed to escalate at 5% then a real dollar analysis would assume 3% escalation of vehicle costs in real dollars.

A12.1 With respect to the first confirmation request, the Company understands that the FortisAlberta base case was presented in nominal dollars using the following assumptions:

- Discount Rate – 7.0 percent
- Internal Labour escalation – 2008-2009 – 5 percent; 4.5 percent thereafter
- Inflation – 2.6 percent in 2008, 2.5 percent thereafter
- Capital Cost Allowance (Class 1) – 4.00 percent
- Meter Depreciation – 5.72 percent
- Engineering and Supervision – 8.0 percent in 2008, 7.5 percent thereafter
- Income Tax Rate (combined federal and provincial on equity):
  2007 – 31.0 percent
  2008 – 30.5 percent
  2009 – 30.0 percent
  2010 – 29.0 percent
  2011 – 28.5 percent

- Return:
  Equity Component – 37.00 percent
  Debt Component – 63.00 percent
  Equity Return – 9.00 percent
  Debt Return – 6.00 percent

With respect to the explanation requested in the second sentence, FortisBC assumes that it is being asked to comment on the appropriateness of its own inflation assumptions, and not those of FortisAlberta. The Company felt it was appropriate to present a conservative analysis and therefore used zero percent as the escalation factor (resulting in the lowest benefit). As was evident in the scenario analysis, the DCF analysis is very sensitive to the various escalation rate assumptions (primarily labour) due to the high operating costs associated with the status quo method reading meters. The Company agrees that it is appropriate to use a real escalation factor in a real dollar analysis.

Q12.2 Please prepare new version of the real dollar analysis and sensitivities that includes real escalation and sensitivities to assumptions about real escalation.

A12.2 Please see the analysis below. Sensitivities were modeled around base assumptions as follow:

- Discount Rate – 8.0 percent
- Internal Labour escalation –1.0 percent real
- Vehicle Cost escalation – 3.0 percent real
- General Inflation – 0.0 percent
- Composite Capital Cost Allowance – 14.38 percent
- Composite Depreciation Rate – 4.20 percent

- Income Tax Rate (combined federal and provincial on equity):
  - 2008 – 31.5 percent
  - 2009 – 31.0 percent
  - 2010 – 30.0 percent
  - 2011 – 28.5 percent
  - 2012 and beyond – 27.0 percent
- Return:
  - Equity Component – 40.0 percent
  - Debt Component – 60.0 percent
  - Equity Return – 9.02 percent
  - Debt Return – 6.43 percent

Scenario

A1	**Discount Rate**	**FBC WACC 6.3 Percent**	**8.0 Percent**	**10.0 Percent**
			(In Real $000s)	
	Status Quo	46,889	40,043	33,892
	AMI	42,133	39,540	37,091
	Net Benefit (Cost)	4,756	503	(3,199)

A2	**Labour Cost Escalation**	**0.0 Percent**	**1.0 Percent**	**2.0 Percent**
			(In Real $000s)	
	Status Quo	37,657	40,043	42,792
	AMI	39,218	39,540	39,895
	Net Benefit (Cost)	(1,561)	503	2,897

A3	**Vehicle Cost Escalation**	**2.0 Percent**	**3.0 Percent**	**4.0 Percent**
			(In Real $000s)	
	Status Quo	39,371	40,043	40,823
	AMI	39,522	39,540	39,558
	Net Benefit (Cost)	(151)	503	1,264

A4	**General Inflation**	**0.0 Percent**	**1.0 Percent**	**2.0 Percent**
			(In Real $000s)	
	Status Quo	40,043	40,594	41,225
	AMI	39,540	39,940	40,406
	Net Benefit (Cost)	503	654	819

Q12.3 Please provide a version of the model that allows separate input of assumptions of real and general price inflation for those items where real inflation is potentially a factor (e.g., labour costs and vehicle expenses).

A12.3 The requested model has been filed in confidence with the Commission.

13.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q12.0, p. 14-27

Project Costs

Q13.1 Please provide a detailed summary sheet showing the underlying methodology and calculations for each of the deferral scenarios (Scenario C1).

A13.1 Each of the scenarios was analyzed in nominal dollars using the following assumptions:

- Discount Rate – 8.0 percent
- Internal Labour escalation –3.0 percent
- Vehicle Cost escalation – 5.0 percent
- General Inflation – 2.0 percent
- Composite Capital Cost Allowance – 14.38 percent
- Composite Depreciation Rate – 4.20 percent
- Income Tax Rate (combined federal and provincial on equity):
  - 2008 – 31.5 percent
  - 2009 – 31.0 percent
  - 2010 – 30.0 percent
  - 2011 – 28.5 percent
  - 2012 and beyond – 27.0 percent
- Return:
  - Equity Component – 40.0 percent
  - Debt Component – 60.0 percent
  - Equity Return – 9.02 percent
  - Debt Return – 6.43 percent

In each case the capital cost of the project was assumed to remain the same as in the base case on the premise that as the technology is implemented by a greater number of utilities across more jurisdictions, that economies of scale will hold prices at today's levels.

The Company has discovered an error in the C1 analysis and provides a revised copy of table C1 below. The revised analysis still illustrates that in each case the net benefit of the project is eroded due to the delay in realizing reduced operating costs associated with the project.

C1	Defer Project	CPCN Application	Defer One Year	Defer Three Years	Defer Five Years
		(In Nominal $000s)			
	Status Quo	48,830	48,830	48,830	48,830
	AMI	41,188	41,290	41,691	42,261
	Net Benefit (Cost)	7,642	7,540	7,139	6,570

A copy of the DCF for each scenario follows:

Project No. 3698493: Advanced Metering Infrastructure (AMI) Project
Requestor Name: BC Utilities Commission
Information Request No:
To: FortisBC Inc.
Request Date: March 5, 2008
Response Date: March 19, 2008

Discounted Cash Flow Analysis
Option "AMI"
Scenario C1 - Defer One Year

Line No.		NPV @ 8.00%	0 Dec-08	1 Dec-09	2 Dec-10	3 Dec-11	4 Dec-12	5 Dec-13	6 Dec-14	7 Dec-15	8 Dec-16	9 Dec-17	10 Dec-18	15 Dec-23	20 Dec-28	25 Dec-33
	Summary															
	Discounted Cash Flow															
1	**Capital Costs**															
2	Meter Costs															
3	New	**1,219**	89	91	178	145	112	114	113	112	109	107	104	90	62	64
4	Replacement	**14,918**	0	0	6,863	11,381	0	0	0	0	0	0	0	0	0	0
4		**16,137**	**89**	**91**	**7,040**	**11,525**	**112**	**114**	**113**	**112**	**109**	**107**	**104**	**90**	**62**	**64**
5	Meter Reading Equipment	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Network Infrastrucuture	**5,172**	0	0	3,176	3,085	0	0	0	0	0	0	0	0	0	0
7	IT infrastructure and upgrades	**1,179**	0	0	1,242	144	0	0	0	0	0	0	0	0	0	0
8	Project Management	**2,143**	0	515	989	1,031	0	0	0	0	0	0	0	0	0	0
9		**24,632**	89	606	12,448	15,785	112	114	113	112	109	107	104	90	62	64
10	**Operating Costs**															
11	Meter Reading															
12	Labour	**5,792**	1,595	1,687	1,778	1,398	0	0	0	0	0	0	0	0	0	0
13	Non-Labour	**1,905**	515	552	590	470	0	0	0	0	0	0	0	0	0	0
14		**7,697**	2,111	2,239	2,367	1,868	0	0	0	0	0	0	0	0	0	0
15	T&D operating cost	**2,532**	281	294	306	318	0	0	0	0	0	0	0	429	491	560
16	Customer service	**6,245**	265	276	286	369	522	535	549	563	578	593	608	691	787	896
17	Income taxes	**184**	0	0	(297)	(625)	(510)	(333)	(187)	(66)	36	121	196	397	447	425
18		**16,658**	2,657	2,809	2,662	1,930	12	203	362	498	614	714	804	1,517	1,725	1,882
19	**GHG Reduction (217.6 tonnes)**	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	**Net Cash Flow**	**41,290**	**2,746**	**3,415**	**15,110**	**17,715**	**123**	**316**	**475**	**610**	**723**	**821**	**908**	**1,607**	**1,787**	**1,946**
21	**Discounted Cash Flow**	**41,290**	**2,746**	**3,162**	**12,955**	**14,063**	**91**	**215**	**300**	**356**	**391**	**411**	**421**	**507**	**383**	**284**

Discounted Cash Flow Analysis
Option "AMI"
Scenario C1 - Defer Three Years

Line No.		NPV @ 8.00%	0 Dec-08	1 Dec-09	2 Dec-10	3 Dec-11	4 Dec-12	5 Dec-13	6 Dec-14	7 Dec-15	8 Dec-16	9 Dec-17	10 Dec-18	15 Dec-23	20 Dec-28	25 Dec-33
	Summary															
	Discounted Cash Flow															
1	**Capital Costs**															
2	Meter Costs															
3	New	**1,073**	89	91	81	66	112	114	113	112	109	107	104	90	62	64
4	Replacement	**12,790**	0	0	0	0	6,863	11,381	0	0	0	0	0	0	0	0
4		**13,863**	**89**	**91**	**81**	**66**	**6,974**	**11,494**	**113**	**112**	**109**	**107**	**104**	**90**	**62**	**64**
5	Meter Reading Equipment	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Network Infrastrucuture	**4,434**	0	0	0	0	3,176	3,085	0	0	0	0	0	0	0	0
7	IT infrastructure and upgrades	**1,011**	0	0	0	0	1,242	144	0	0	0	0	0	0	0	0
8	Project Management	**1,838**	0	0	0	515	989	1,031	0	0	0	0	0	0	0	0
9		**21,146**	89	91	81	581	12,382	15,754	113	112	109	107	104	90	62	64
10	**Operating Costs**															
11	Meter Reading															
12	Labour	**8,631**	1,595	1,687	1,778	1,864	1,947	1,525	0	0	0	0	0	0	0	0
13	Non-Labour	**2,876**	515	552	590	627	663	527	0	0	0	0	0	0	0	0
14		**11,506**	2,111	2,239	2,367	2,491	2,610	2,052	0	0	0	0	0	0	0	0
15	T&D operating cost	**3,004**	281	294	306	318	329	340	0	0	0	0	0	429	491	560
16	Customer service	**5,928**	265	276	286	295	303	391	549	563	578	593	608	691	787	896
17	Income taxes	**106**	0	0	0	0	(256)	(574)	(504)	(333)	(189)	(68)	39	340	436	437
18		**20,545**	2,657	2,809	2,959	3,104	2,986	2,208	45	230	388	525	647	1,460	1,715	1,893
19	**GHG Reduction (217.6 tonnes)**	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	**Net Cash Flow**	**41,691**	**2,746**	**2,900**	**3,040**	**3,684**	**15,369**	**17,962**	**158**	**342**	**498**	**632**	**750**	**1,550**	**1,777**	**1,957**
21	**Discounted Cash Flow**	**41,691**	**2,746**	**2,685**	**2,606**	**2,925**	**11,296**	**12,225**	**99**	**199**	**269**	**316**	**348**	**489**	**381**	**286**

Project No. 3698493: Advanced Metering Infrastructure (AMI) Project
Requestor Name: BC Utilities Commission
Information Request No: 2
To: FortisBC Inc.
Request Date: March 5, 2008
Response Date: March 19, 2008

Discounted Cash Flow Analysis
Option "AMI"
Scenario C1 - Defer Five Years

Line No.		NPV @ 8.00%	0 Dec-08	1 Dec-09	2 Dec-10	3 Dec-11	4 Dec-12	5 Dec-13	6 Dec-14	7 Dec-15	8 Dec-16	9 Dec-17	10 Dec-18	15 Dec-23	20 Dec-28	25 Dec-33
	Summary															
	Discounted Cash Flow															
1	**Capital Costs**															
2	Meter Costs															
3	New	**986**	89	91	81	66	51	51	113	112	109	107	104	90	62	64
4	Replacement	**10,965**	0	0	0	0	0	0	6,863	11,381	0	0	0	0	0	0
4		**11,951**	**89**	**91**	**81**	**66**	**51**	**51**	**6,976**	**11,493**	**109**	**107**	**104**	**90**	**62**	**64**
5	Meter Reading Equipment	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Network Infrastrucuture	**3,802**	0	0	0	0	0	0	3,176	3,085	0	0	0	0	0	0
7	IT infrastructure and upgrades	**867**	0	0	0	0	0	0	1,242	144	0	0	0	0	0	0
8	Project Management	**1,575**	0	0	0	0	0	515	989	1,031	0	0	0	0	0	0
9		**18,195**	89	91	81	66	51	566	12,384	15,753	109	107	104	90	62	64
10	**Operating Costs**															
11	Meter Reading															
12	Labour	**11,284**	1,595	1,687	1,778	1,864	1,947	2,033	2,123	1,662	0	0	0	0	0	0
13	Non-Labour	**3,796**	515	552	590	627	663	702	733	582	0	0	0	0	0	0
14		**15,081**	2,111	2,239	2,367	2,491	2,610	2,736	2,856	2,244	0	0	0	0	0	0
15	T&D operating cost	**3,225**	281	294	306	318	329	340	351	0	0	0	0	429	491	560
16	Customer service	**5,781**	265	276	286	295	303	312	402	563	578	593	608	691	787	896
17	Income taxes	**(22)**	0	0	0	0	0	0	(251)	(574)	(506)	(335)	(185)	253	412	442
18		**24,065**	2,657	2,809	2,959	3,104	3,242	3,387	3,358	2,233	72	258	423	1,373	1,690	1,898
19	**GHG Reduction (217.6 tonnes)**	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	**Net Cash Flow**	**42,261**	**2,746**	**2,900**	**3,040**	**3,169**	**3,293**	**3,953**	**15,741**	**17,986**	**181**	**365**	**526**	**1,463**	**1,753**	**1,962**
21	**Discounted Cash Flow**	**42,261**	**2,746**	**2,685**	**2,606**	**2,516**	**2,420**	**2,691**	**9,920**	**10,494**	**98**	**183**	**244**	**461**	**376**	**287**

Q13.2 Is it possible to utilize AMI-capable meters for new customer installs before the full implementation of AMI (i.e., replacement of existing meters)? Are there any issues with this?

A13.2 Once an AMI technology has been chosen, AMI-enabled meters could be utilized in customer installations before AMI has been implemented in their area and read manually until the installation of the AMI communications infrastructure. The only additional requirement in this case would be that once the AMI communications system has been installed in that area, a series of remote tests would be required to ensure that there are no communications issues with the meter. These tests would not be able to be completed during the initial replacement due to the lack of the communications infrastructure at that time.

14.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q12.0, p. 14-27

Project Costs

Q14.1 The DCF analysis shows positive net income taxes of $128 (NPV @8%). The Revenue Requirements Model shows negative net income taxes of $235k (NPV @10%). Please reconcile the differences.

A14.1 The difference is due to the different discount rates. If the same discount rate is used, the NPV of income tax is also the same.

15.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q12.0, p. 14-27

Project Costs

Q15.1 Please re-run the economic analysis using a "least cost meter", that is, a project replacing existing meters with meters that have only the functionality necessary to provide all the savings included in the economic analysis?

A15.1 The cost of the AMI system included in the CPCN Application is the "least cost meter" which contains only the required functions and features to deliver on the economic and soft benefits within the Application. Adding the future requirements listed in Table 7.1 from the CPCN Application (Exhibit B-1) at this time, does not add any cost into the initial installation.

Please also refer to the response to BCOAPO IR No. 1 Q10.2 (Exhibit B-2).

Q15.2 Please also prepare economic analysis or comment on the economics for a drive-by AMR system?

A15.2 Drive-by meter reading technology (AMR) has the potential to improve productivity and lower operating costs compared to FortisBC's existing process. The number of employees could be reduced to about 8 from the current staff of 18. The reduced staff lessens the exposure to the inflationary pressures of labour and fuel although some exposure still remains. The reduced number of staff and vehicles also lessens the exposure hours to potentially hazardous conditions and reduces vehicle emissions. Bill errors resulting from manual entry errors would be eliminated, however meter read estimates may still be required.

The current process for collecting off cycle reads (on/off, re-reads) would see only a slight benefit as a vehicle and reader would still need to be dispatched to the service point to collect the read. While potential exists for improvement in meter reading costs and efficiency, the benefits provided by a mobile meter reading system when compared to two-way communicating AMI technologies are significantly less, despite both solutions requiring considerable investment in the upgrade/replacement of all metered endpoints in the service territory.

Table A15.2 below displays the comparative features and costs of AMI, drive by AMR, and the status quo manual method of meter reading.

Table A15.2: Benefits Comparison with AMI

Features Available	AMI	AMR	Status Quo
Bi-Monthly Meter Readings	▲	▲	▲
Monthly Meter Readings	▲	▲	
Daily Meter Readings	▲		
Outage Notification	▲		
Restoration Verification	▲		
Virtual Disconnects	▲		
Flexible Billing Dates	▲		
Bill Consolidation for Customers	▲		
Voltage Readings	▲		
System Modeling	▲		
Customer Load Profiles	▲		
Capital Costs ($000)			
Meters and Modules	19,507	17,784	0
Network Infrastructure	6,700	35	0
IT Infrastructure and Upgrades	1,483	235	0
Project Management	2,701	599	0
Total Capital Costs	**30,391**	**18,563**	**0**

The NPV revenue requirements analysis over 25 years in an AMR system is approximately $4.9 million with a corresponding NPV rate impact of -0.22 percent.

Q15.3 Please provide a description of the functionality of the "least cost meter", and a description of the functionality required to deliver the savings included in the economic analysis?

A15.3 Please refer to Table 7.1 from the CPCN Application (Exhibit B-1). Please also refer to the response to BCOAPO IR No. 1 Q10.2 (Exhibit B-2).

Q15.4 Please comment on whether or not the Commission should either 1) only approve the project using "least cost meters" or 2) delay approval until the Company can provide economic analysis to justify the incremental functionality?

A15.4 Project cost within the CPCN Application is based on the "least cost meter".

16.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q12.0 and Wait Q22, p. 8

Q16.1 FortisBC states it "… has used a real discount rate of 8.0 percent as a base case in evaluating its capital expenditures for a number of years." Please provide the source document for the first use of the real discount rate of 8.0%? Please explain why 8.0% is still appropriate for evaluating capital expenditures? Please explain why the use of a discount rate with no customer impacts is consistent with the opinion that the "correct cash flow for project evaluations is the incremental cash flow required from customers"?

A16.1 Please see the attachment below:

West Kootenay Power Ltd.
1996 Revenue Requirements Application
Question #49
Ref: General IRP

What discount rate or rates were used for WKP's IRP analyses?

Answer #49

Generally in B.C., including B.C. Hydro and the Crown Corporations Secretariat, an 8% real social discount rate is used. WKP also used the 8% real rate for its IRP analysis. This rate is equivalent to an 11% nominal rate given a long term inflation rate of 3%.

As noted in the Company's response to BCUC IR No. 1 Q12.0 (Exhibit B-2), the Company is of the opinion that a discount rate of 8.0 percent is within a reasonable range in historical terms and that sensitivity analysis around the discount rate provides an assessment of the discount rate risk.

The Company assumes that the last part of the question is asking whether a different discount rate would be appropriate when evaluating the incremental cash flow required from customers in the form of revenue requirements (the ratepayer impact analysis) versus the incremental cash flow to the Company resulting from a particular project (the economic impact analysis). The Company is of the opinion that the same discount rate should be used for either evaluation.

Q16.2 FortisBC states that its after-tax weighted average cost of capital has been set for rate setting purposes at 6.3% indicating a nominal discount rate of 8.3% assuming inflation of 2%. Please explain why FortisBC considers the approved WACC a real rate given it is based on nominal and not real interest rates. If FortisBC agrees that the 6.3% is already a nominal rate, would it also agree the equivalent real WACC is approximately 4.3%?

A16.2 FortisBC did not mean to imply that the Company's WACC is a real rate. The Company was noting that in BCUC Reasons for Decision with regard to BC Hydro's 2006 Integrated Electricity Plan and 2006 Long Term Acquisition Plan, the Commission examined the question of what is the appropriate discount rate for BC Hydro to use when calculating the economic and rate impact analysis of major projects. The Commission concluded on page 184 that:

"major capital projects should be considered to be financed at the Utility's weighted average cost of capital."

Therefore, the Company believes that in nominal terms the correct discount rate for evaluating projects is the Company's WACC and agrees that the equivalent real WACC is approximately 4.3 percent.

Q16.3 Please provide an updated discount rate sensitivity for the DCF analysis (Scenario A1) also assuming a real WACC of ~4.3%.

A16.3 As noted in the table below, the project would yield a net benefit DCF of approximately $5.2 million assuming a real WACC of 4.3 percent.

A1	**Discount Rate**	**FBC WACC 4.3 Percent**	**8.0 Percent**	**10.0 Percent**
			(In Real $000s)	
	Status Quo	50,644	35,896	30,675
	AMI	45,474	39,164	36,776
	Net Benefit (Cost)	5,170	(3,268)	(6,101)

17.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q15.3, p. 32

AMI unit costs

Q17.1 Would FortisBC please explain why it does not have sufficient information to respond to this question and why it has not or did not obtained the information it required from FortisAlberta?

A17.1 FortisBC does not have access to the requested information as it is protected by a contract confidentiality clause between FortisAlberta and the AMI third party vendor. To the best of its abilities, FortisBC has provided a cost comparison from FortisAlberta in response to BCUC IR No. 2 Q9.5.

18.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q15.4, p. 33
AMI unit costs

Q18.1 Would FortisBC please explain why it does not have sufficient information to respond to this question and why it has not or did not obtained the information it required from FortisAlberta?

A18.1 Please refer to the response to BCUC IR No. 2 Q17.1.

19.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q15.5, p. 34
AMI unit costs

Q19.1 Does FortisBC accept the cost of about $260 per meter as representative since the apparent difference is about $30/meter or about $3,000,000 in capital cost?

A19.1 FortisBC believes that the question referenced above should have been Q15.4.2 rather than the stated Q15.5. FortisBC accepts the cost of about $260 per meter as representative.

20.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q15.5, p. 35

AMI unit costs

Q20.1 Would FortisBC please explain why it does not have sufficient information to respond to this question?

A20.1 In order to answer this question, FortisBC would have to understand the detailed requirements of the Hydro One system as well as have access to Hydro One Vendor contracts. Neither of these items are publicly available. Furthermore, because FortisBC believes that the cost reflected in the Hydro One application reflects only a portion of the AMI costs and not the cost to implement a complete AMI system, FortisBC could not answer this question with any certainty.

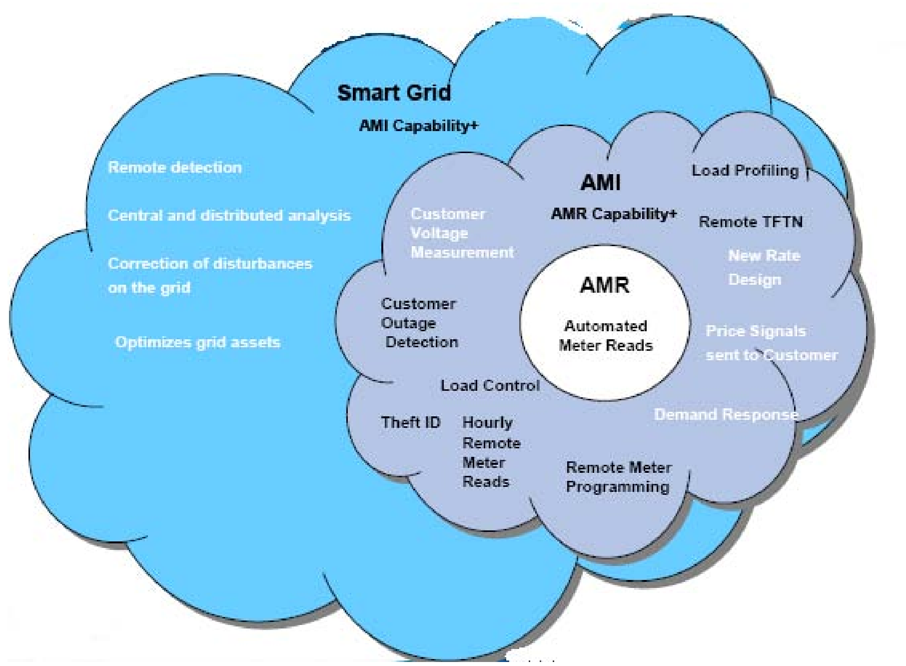
21.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q15.5, Set C – Capital Cost Sensitivities, p. 23

AMI Deferral

Q21.1 Has FortisBC reviewed the EPRI IntelliGrid Consumer Portal Telecommunications Assessment and Specification, Technical Report 2005 and included these customer issues into their equipment specifications?

A21.1 FortisBC has reviewed the EPRI IntelliGrid Consumer Portal Telecommunications Assessment and Specification report and where appropriate, considered the issues within the scope of the CPCN Application. FortisBC believes there needs to be a balance between anticipating and supporting the concepts of Smart Grid infrastructure, and making tangible benefits (cost savings, customer service, environmental benefits) available to customers now.

Q21.2 As a Smart Grid can be approximately characterized by the diagram below, would FortisBC please confirm the elements that their AMI proposal lacks to be classified as a Smart Grid?



A21.2 FortisBC's confirms that the AMI application submitted is not intended to be an all-encompassing "Smart Grid" solution. AMI is an important component of the Smart Grid concept as it provides the remote meter programming, customer outage detection, new rate design, daily load profiling and automated meter reading functions shown in the diagram. The Company believes that it is important to implement the basic meter reading functions of AMI day one, to ensure that customers can receive benefits of the AMI system sooner. The flexible and robust nature of the AMI system will allow "smart grid" functions to be added to the base infrastructure in the future.

Q21.3 Would FortisBC please identify all features available to an AMI system and those features that they are currently not providing at this time and those features that they have decided not to provide in the future as well?

A21.3 The AMI system described in this Application does not include two main features that are generally available:

- Provision for hourly or more frequent readings through a Validation, Estimation and Editing (VEE) equipped Meter Data Management Repository (MDMR)

- In-home display capability through a Home Area Network (HAN)

FortisBC has not decided not to provide these features in the future.

Q21.4 Would FortisBC please provide a very brief discussion on the differences, benefits and drawbacks, between AMR, AMI, Smart Meters, Intelligent Grid, Wide Area Measurement System (WAMS) and DOE Grid 2030 systems?

A21.4 An AMR system is an automated way to read meters. Details on the benefits and drawbacks of an AMR system are discussed in BCUC IR No. 2 Q 15.2.

FortisBC defines “Smart Meters” as meters that contain a communications component to integrate them into the overall AMI system. AMI generally relates to not only the meters, but also the infrastructure required to connect the meters to the utility and deliver on the benefits typically offered within an AMI system. These benefits are discussed in detail in Section 4.1 of the Application (Exhibit B-1). AMI systems are an important part of the smart grid, and contribute a significant portion of the operational, customer satisfaction, and load management benefits.

FortisBC understands that Intelligent Grid, WAMS and DOE Grid 2030 are all concepts relating to the concept of the "Smart Grid". FortisBC understands that the original smart grid concept evolved through efforts of the Electric Power Research Institute (EPRI) and envisioned an intelligent utility network that was comprised of electronic measurement devices and distributed generation integrated over a common communications link between the utility and the customer. Industry organizations such as GridWorks and the GridWise Alliance have helped to further define the smart grid vision.

The important principles and characteristics that have come to define the smart grid are:

- The Smart Grid is an intelligent, secure and self-healing, distributed power delivery network that provides reliable electric service to customers with improved operational efficiency;
- It employs an advanced communications network that provides real time communications among many intelligent network devices, supports load and asset monitoring functions and helps to balance varying energy costs with changing customer usage;
- The Smart Grid utilizes interoperability requirements to encourage use of a wide variety of AMI, SCADA and distribution automation network devices under a continuous network improvement strategy for managing energy use; and
- It supports distributed generation as a means of increasing energy

supply and improving power flow through access to remote generation sources such as wind, solar and renewable energy sources. Through AMI, it also encourages use of peak shaving and load curtailment technologies that delay the need for additional sources of energy supply.

Q21.5 Considering that the National Institute of Standards and Technology is to have primary responsibility for coordinating the framework - protocols and model standards, coordinating with DOE, Smart Grid Task Force and Advisory Council, would FortisBC be able to be in compliance with a future standard at this time or would FortisBC consider it advisable to wait for the future development of the Smart Grid Interoperability Framework to be developed?

A21.5 Many of the utilities that are proceeding with AMI implementations (such as FortisAlberta, ATCO Electric, and those in the Province of Ontario), have already successfully dealt with the standards issues, and have identified qualifying smart metering suppliers that can meet the national standards. During the initial and secondary phases of Ontario's Smart Metering Initiative local distribution companies have been successfully deploying smart metering solutions, and the province is already well on its way to achieving full implementation by 2010. Therefore, FortisBC considers it appropriate to proceed with the Project.

Q21.6 Do the AMI systems under consideration have compatible features that are addressed in the vision for DOE Grid 2030? Please identify in the table below.

FortisBC AMI 2008	DOE GRID 2030 2010	DOE GRID 2030 2020
	Customer "gateway" for the next generation "smart meter", enabling two-way communications and a "transactive" customer-utility interface	Customer "total energy" systems for power, heating, cooling, and humidity control with "plug & play" abilities, leasable through mortgages
	Intelligent homes and appliances linked to the grid	
	Programs for customer participation in power markets through demand side management and distributed generation	

A21.6 The U.S. Department of Energy's futuristic concept of DOE Grid 2030 is an improvement strategy that builds on technology advances identified through today's Smart Grid vision and which continues to promote interoperability standards and use of intelligent and secure network devices that balance energy use with supply. DOE Grid 2030 envisions a fully digital communications network which optimizes energy delivery through continuing improvements in network controls but also through reduction of energy losses from improvements in advanced conducting devices, energy storage capabilities, advanced switching and other technologies.

Another way of describing the DOE Grid 2030 vision is as a plan to build on the use of Smart Grid technologies and strategies being implemented today to drive further improvements that optimize, and more fully utilize, today's electric grid.

DOE Grid 2030 envisions a fully automated power delivery system that optimizes the flow of electric power and communications between energy suppliers and the end-user.

AMI provides the two-way communications infrastructure and energy measurement capabilities that enable many of these functions to take place. FortisBC believes that the requirements set out in the Application are sufficient to support baseline Smart Grid interoperability requirements while supporting future technology developments. Examples of these requirements are:

- Two way communications and AMI functions that support time based rates on the meter will be specified; and
- Customer access to energy consumption information through web portals will be required; and
- Home area networking functions enabled through use of Wireless or power line carrier technologies and protocols such as ZigBee, Z-Wave, WiFi, HomePlug, Modbus and others will be given a high priority, although are not considered required.

These features are already being implemented in the U.S. and in the Province of Ontario where the Smart Metering Initiative is well underway.

Q21.7 Would FortisBC please explain why it would not be a reasonable and prudent decision to defer the AMI project until the BC Hydro Smart Metering Initiative has been determined by the Commission? Has FortisBC and BC Hydro had any discussions on this issue? If so, please explain.

A21.7 FortisBC is of the opinion that the AMI project is cost effective, offers benefits to customers and supports the BC Energy Plan. It is therefore a prudent expenditure at this time. FortisBC is a stand-alone utility, which does not have control over the inclusions, exclusions, or timing of the BC Hydro Smart Metering Initiative. As a result of FortisBC's ongoing consultation with BC Hydro, the Ministry of Energy, Mines and Petroleum Resources and FortisBC customers, FortisBC is confident that its AMI implementation project is both necessary and desired to provide customers with the required tools to achieve the energy savings benefits as outlined in the BC Energy Plan. For the reasons set out above and in the Application, FortisBC is of the opinion that it is reasonable and prudent for the Company to begin its AMI implementation now, which would also allow BC Hydro the opportunity to observe a full scale implementation (100,000+ customers) in the Province. FortisBC respectfully submits that any delay in this project is not in the best interest of FortisBC customers.

Q21.8 If the BC Hydro Smart Metering Initiative is successful, then BC Hydro would be purchasing in excess of 1,000,000 meters and associated equipment. Would FortisBC consider combining forces with the BC Hydro Smart Metering Initiative so that the efficient purchasing of equipment would be more effective not to mention the standardization of FortisBC's equipment with the dominate utility in BC.

A21.8 FortisBC is of the opinion that there is no benefit to delaying its AMI Project in order to combine forces with BC Hydro. As well, FortisBC has been involved in multiple discussions with BC Hydro to ensure that, where it makes sense, the equipment chosen by FortisBC would not be inconsistent with the equipment chosen by BC Hydro. BC Hydro will likely have to utilize more than one technology in its Smart Metering implementation due the fact that BC Hydro's service territory encompasses areas ranging from very dense urban to very sparse rural. This need for a number of AMI technologies to serve the Province of British Columbia would likely reduce any advantages from economies of scale for AMI implementations. Moreover, the economics of the AMI Project on a standalone basis are favorable and of significant benefit to FortisBC customers. Please also refer to the response to BCUC IR No. 2 Q21.7.

Q21.9 Other than the cost of deferring the project at about $100,000 per year, what would FortisBC perceive as other issues?

A21.9 In addition to those listed in BCUC IR No. 2 Q21.7 and Q21.8, other issues are as follows:

- FortisBC's customers could not immediately receive the benefits outlined in the CPCN Application, including:
    - Improved billing accuracy;
    - Reduced access to customer property;

    - Access to more detailed consumption information;
    - Actual verified readings on the day of move in / out;
    - Improved high bill resolution; and
    - Actual verified readings on Equal Payment Plan bills.
- Costs of the current meter reading practice will continue to be exposed to high inflationary pressures;
- A technology that suits customers, service territories and business needs of both FortisBC and BC Hydro would unnecessarily limit the number of AMI vendors which could have an upward pressure on the price of both AMI systems; and

For the reasons above, a joint process could unnecessarily delay the AMI Project process for both utilities thereby delaying the implementation of conservation initiatives in support of the BC Energy Plan.

22.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q15.1, p. 30

Project Costs

Q22.1 Without disrespect for Commission Order No. G-58-06, please provide FortisBC's or other utilities expected life in years for:

	Measurement Canada Certified Life In Years	Technological Life In Years	Economic Life In Years	Useful Life In Years
Smart Meters				
Computer Hardware				
Software				
Communication Network Systems				

A22.1 The following estimates are based on FortisBC's experience. Please see Table A22.1 below.

Table A22.1: Expected Life (Years)

	Measurement Canada Certified Life	Technological Life	Economic Life	Useful Life
Smart Meters	10	25	25	25
Computer Hardware	N/A	5	5	5
Software	N/A	5 – 10	5	5 – 10
Communication Network Systems	N/A	5 – 10	15	15 – 20

Q22.2 Please supply the applicable portions of the 2005 Depreciation Study.

A22.2 Please see the following Table 1 from page III-4 of the Company's 2005 Depreciation Study. Note that the Survivor Curve for Account 370.0 Meters is based on a 25 year life.

FORTISBC INC.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2004

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2004	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	GENERATION PLANT								
330.1	LAND RIGHTS	75-R4	0	98,939.00	-	98,939	2,550	2.58	38.8
331.0	STRUCTURES AND IMPROVEMENTS	65-L3	-10	9,783,130.00	3,884,309	6,877,134	118,725	1.21	57.9
332.0	RESERVOIRS, DAMS, AND WATERWAYS	75-R4	-10	14,551,623.00	2,831,094	13,175,691	252,910	1.74	52.1
333.0	WATER WHEELS, TURBINES, AND GENERATORS	75-R3	-50	36,701,157.00	1,835,285	53,216,451	816,412	2.22	65.2
334.0	ACCESSORY ELECTRICAL EQUIPMENT	45-R2.5	-30	17,632,807.00	5,377,685	17,544,964	421,995	2.39	41.6
335.0	OTHER POWER PLANT EQUIPMENT	45-R3	-5	36,000,966.00	3,720,997	34,080,019	809,374	2.25	42.1
336.0	ROADS, RAILROADS AND BRIDGES	75-S4	0	1,046,225	153,191	893,035	14,531	1.39	61.5
346.0	OTHER PRODUCTION PLANT - EQUIPMENT	40-R4	0	1,352,834	1,352,834	-	-	-	0.0
	TOTAL GENERATION PLANT			117,167,681	19,155,395	125,886,233	2,436,497		
	TRANSMISSION PLANT								
350.1	LAND RIGHTS	75-R3	0	9,004,433	707,655	8,296,778	140,843	1.56	58.9
353.0	SUBSTATION EQUIPMENT	50-S3	-30	56,096,067	15,935,058	56,989,828	1,828,897	3.26	31.2
355.0	POLES, TOWERS AND FIXTURES	45-S2	-50	48,119,868	10,146,568	62,033,234	1,793,769	3.73	34.6
356.0	CONDUCTORS AND DEVICES	50-R3	-50	49,699,990	7,905,649	66,644,334	1,749,212	3.52	38.1
359.0	ROADS AND TRAILS	40-R0.5	0	760,193	(47,409)	807,602	21,871	2.88	36.9
	TOTAL TRANSMISSION PLANT			163,680,551	34,647,521	194,771,776	5,534,592	14.95	
	DISTRIBUTION PLANT								
360.1	LAND RIGHTS	75-R3	0	2,812,598	117,901	2,694,697	59,659	2.12	45.2
362.0	SUBSTATION EQUIPMENT	45-R2.5	-30	78,507,045	20,512,165	81,546,996	2,352,810	3.00	34.7
364.0	POLES, TOWERS AND FIXTURES	40-R3	-40	72,574,830	22,102,625	79,502,137	2,937,494	4.05	27.1
365.0	CONDUCTORS AND DEVICES	40-R3	-25	126,777,091	31,564,283	126,907,081	4,331,295	3.42	29.3
368.0	LINE TRANSFORMERS	45-L2.5	-25	51,368,229	14,049,209	50,161,078	1,479,663	2.88	33.9
369.0	SERVICES	75-R4	0	6,090,373	6,090,373	-	-	-	0.0
370.0	METERS	25-L1	0	10,123,611	3,768,923	6,354,686	352,329	3.48	18.0
371.0	INSTALLATIONS ON CUSTOMERS PREMISES	25-R1	0	937,832	937,832	-	-	-	0.0
373.0	STREET LIGHTING AND SIGNAL SYSTEMS	35-R3	-15	2,927,997	1,133,314	2,233,881	69,018	2.36	32.4
	TOTAL DISTRIBUTION PLANT			352,119,606	100,276,625	349,400,556	11,582,268		
	GENERAL PLANT								
390.0	STRUCTURES - FRAME AND IRON	40-R3	0	337,364	245,779	91,588	2,699	0.80	33.9
390.1	STRUCTURES- MASONRY	30-R2	0	16,579,870	1,762,091	14,817,778	981,033	5.92	15.1
391.0	OFFICE FURNITURE AND EQUIPMENT	15-SQ	0	4,383,050	2,041,126	2,341,926	327,662	7.48	7.1
391.1	COMPUTER EQUIPMENT AND SOFTWARE	5-SQ	0	31,602,777	14,871,705	16,731,071	3,346,214	10.59 (*)	5.0
392.0	TRANSPORTATION EQUIPMENT	13-L2.5	20	5,873,914	4,400,520	298,612	25,515	0.43	11.7
394.0	TOOLS AND WORK EQUIPMENT	15-SQ	0	7,026,174	2,729,131	4,297,042	664,731	9.46	6.5
397.0	COMMUNICATIONS STRUCTURES AND EQUIPMENT	15-SQ	0	7,546,508	2,902,671	4,643,836	451,704	5.99	10.3
	TOTAL GENERAL PLANT.			73,349,657	28,953,023	43,221,853	5,799,558		
	TOTAL DEPRECIABLE PLANT			706,317,495	183,032,564	713,280,418	25,352,915	3.59	
	PLANT NOT STUDIED								
389.0	LAND			2,055,420	-				
114.0	UTILITY PLANT ACQUISITION ADJUSTMENT			11,912,000	3,908,600				
390.0	LEASEHOLD IMPROVEMENTS			1,389,779	727,508				
	TOTAL NON - DEPRECIABLE PLANT			15,357,199	4,636,108	-	-		
	TOTAL PLANT			721,674,694	187,668,672	713,280,418	25,352,915		

(*) the remaining life in this account has been adjusted to 5 years to avoid large adjustments in future studies

Q22.3 Please supply justification that the useful, economic, "Measurement Canada" Certified Life and depreciable life is capable of 25 years.

A22.3 The Company expects that the new smart meters will perform much the same as the current electronic meters that have been in service for more than 10 years. The current electronic meters have not reached the end of their expected service lives, however the Company has not experienced any significantly higher or lower failure rate on the current electronic meters as compared to existing mechanical meters to suggest a life shorter or longer than the 25 year expected life currently used.

There is no direct correlation between Measurement Canada's Certified Life and the useful, economic or depreciable life of the meter. The Certified Life is the amount of time that can elapse before the meter (meter group) has to be tested and re-certified for use. Please also refer to the response to BCOAPO IR No. 2 Q21.2.

23.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q14.3, p. 30
Project Costs

Q23.1 Please confirm whether the proposed depreciation approach for existing meters essentially means there is in no incremental rate impact arising from retirement of existing meters relative to the status quo scenario.

A23.1 Confirmed.

Q23.2 Please provide an updated rate impact model incorporating a scenario where the net book value of existing meters is written off over five years.

A23.2 Please see Table A23.2 below.

Project No. 3698493: Advanced Metering Infrastructure (AMI) Project
Requestor Name: BC Utilities Commission
Information Request No:
To: FortisBC Inc.
Request Date: March 5, 2008
Response Date: March 19, 2008

Table A23.2

Revenue Requirements Template
Option "AMI" (Write-off Existing Meters over 5 Years)

Line No.		NPV @ 10.00%	0 Dec-08	1 Dec-09	2 Dec-10	3 Dec-11	4 Dec-12	5 Dec-13	6 Dec-14	7 Dec-15	8 Dec-16	9 Dec-17	10 Dec-18	15 Dec-23	20 Dec-28	25 Dec-33
	Summary															
	Revenue Requirements															
1	Operating Expense (Incremental)	**(26,206)**	0	0	(518)	(2,593)	(2,718)	(2,849)	(2,976)	(3,118)	(3,266)	(3,419)	(3,577)	(4,013)	(4,944)	(6,070)
2	Depreciation Expense	**13,895**	0	0	1,001	2,448	2,451	2,454	2,446	2,045	1,330	1,332	1,335	1,336	1,334	1,331
3	Carrying Costs	**13,335**	0	530	1,686	2,264	2,170	2,066	1,962	1,868	1,773	1,678	1,574	1,078	577	76
4	Income Tax	**(235)**	0	(344)	(742)	(608)	(373)	(207)	(71)	41	134	212	281	459	494	462
5	Total Revenue Requirement for Project	**789**	0	186	1,426	1,512	1,530	1,464	1,361	835	(29)	(196)	(387)	(1,141)	(2,539)	(4,201)
	Rate Impact															
6	Forecast Revenue Requirements		219,817	240,023	255,139	272,208	287,690	293,400	299,300	305,300	311,400	317,600	324,000	357,700	394,900	436,100
7	Rate Impact		0.00%	0.08%	0.56%	0.56%	0.53%	0.50%	0.45%	0.27%	-0.01%	-0.06%	-0.12%	-0.32%	-0.64%	-0.96%
8	**NPV of Project / Total Revenue Requirements**		**0.03%**													

24.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q15.2, p. 32

Project Costs

"The inclusion and complexity of the MDMR can impact the overall cost of an AMI system. For example, most Ontario utilities do not require an MDMR as the Ontario Energy Board (OEB) will be developing and maintaining the MDMR system. Utilities that are implementing an MDMR with validation and estimation capability will have a higher IT cost than those with a basic MDMR."

Q24.1 Please explain the capability of the MDMR or MDMS that FortisBC is proposing for the AMI system and why it should or should not be implemented with validation and estimation capability?

A24.1 As stated in Section 6.3, page 31 of the CPCN Application (Exhibit B-1), the AMI software (MDMR) will be used as the main repository for all data relating to the AMI system. In addition to this, it is also expected that the MDMR will have the following functionality:

- Alert for momentary outages to identify possible tamper situations;
- Flag "no expected usage" accounts to permit investigation when consumption occurs;
- Identify communications issues related to the AMI system;
- Provide the ability for ad-hoc reporting related to all AMI data stored in the AMI software;
- Interface to the Customer Information System (CIS) and Work Order management systems as required; and
- Identification of possible power diversion by comparing usage data between a group of meters and the feeder or substation linked up to those meters.

A complex MDMR system that has validation and estimation (VEE) capability is required if the utility will be receiving hourly readings versus daily readings. VEE fills in any reading gaps within the hourly data making the information more complete and useful for analysis as well as calculating Time of Use buckets and/or Critical Peak timeframes from the hourly (or more frequent) data within the MDMR rather than within the meter itself. FortisBC expects that if TOU or CPP rates were implemented in this fashion in the future, the MDMR component of the project could be upgraded at a cost of approximately $4 million to $6 million.

25.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q15.3, p. 36

AMI unit costs

Q25.1 Does FortisBC agree that historical costs, industry averages and benchmarking are reasonable and prudent methods of reviewing estimated costs?

A25.1 FortisBC agrees that reference to historical costs, industry averages, and benchmarks are useful in reviewing cost estimates. Large variances from expected values may prompt a further review of underlying information. However, as noted in the response to BCUC IR No. 1 Q15.2 (Exhibit B-2), there is a significant range due to the characteristics of specific installations and the factors mentioned in this IR can only form part of the review.

26.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q15.3, p. 36

AMI Non-Project and Estimated Future Costs

Q26.1 Would FortisBC, on a best efforts basis, complete the following table of non-project and future related project costs for adding 36,000 new customers, adding the 34,000 existing municipal customers, adding water meters, adding gas meters, adding remote disconnect/reconnect features to an estimated number of residences with chronic issues?

Non-Project and Future Costs		Direct Costs	Indirect Costs	Total
	Incremental Meter Costs			
	Gas Meters			
	Water Meters			
	34,000 Municipal Meters			
	36,000 Future Electrical Meters			
	Incremental Metering Operational Expenses			
	Incremental Other Operational Expenses			
	Incremental Other Admin Expenses			
	Avoided Future Capital Costs			
	Innovative Rate Structures			
	Load Control			
	Remote Disconnect/Reconnect for ___ meters.			

	Meter Reading Frequency			

A26.1 FortisBC, on a best efforts basis, has completed the following table of non-project and future related project costs.

While referencing the table, it is important to consider the notes below relating to each line within the table.

Table A26.1: Future Related Costs ($000s)

	Non-Project and Future Costs	Direct Costs	Indirect Costs	Total
1	Incremental Meter Costs	1,249	87	1,336
2	Gas Meters	260 – 32,000	18 – 2,240	278 – 34,240
3	Water Meters	Included in 2	Included in 2	Included in 2
4	46,000 Municipal Meters	15,000 – 25,000	1,050 – 1,750	16,050 – 26,750
5	36,000 Future Electrical Meters	See line 1	See line 1	See line 1
6	Incremental Metering Operational Expenses	0	0	0
7	Incremental Other Operational Expenses	524	0	524
8	Incremental Other Admin Expenses	0	0	0
9	Avoided Future Capital Costs	(1,162)	(88)	(1,250)
10	Innovative Rate Structures	150 – 8,000	10 – 560	160 – 8560
11	Load Control	0 – 2,000	0 – 140	0 – 2,140
12	Remote Disconnect/Reconnect for 500 meters	99	7	107
13	Meter Reading Frequency (Monthly)	0	0	0

The incremental number of municipal customers has been corrected to 46,000 as the response to BCUC IR No. 2 Q1.1.

2, 3, 4 – If gas, water or municipal meters were added to the AMI infrastructure, FortisBC customers would not be expected to bear the incremental capital costs associated with their addition. Total costs to provide service to gas and water meters does not include the cost of purchasing and installing AMI-enabled gas and water meters if required.

2 - The lower range of costs is if the communications module is standard within the AMI meter at no additional cost. The higher range is if the meters needed to be removed, the communications module added and then the meters re-sealed and re-installed.

4 – The lower end of the range is if the meters could be installed at the same price per meter as FortisBC’s direct customers at $290 per meter. The higher end of the range is if significant infrastructure would be required to support these meters which would bring the cost to approximately $525 per meter.

5 – This is the same item as line 1.

10 – Actual cost will depend on the structure and complexity of the rates, the number of customers on those rates. The lower end of the range reflects rates that can be supported by calculations on the meter. The higher end of the range reflects dynamic pricing and complex rates that are better supported through the upgrade of the MDMR to have Validation, Estimation and Editing (VEE) capability as well as the addition of a Home Area Network and upgrades to FortisBC’s billing system.

11 – Reflects the upgrades to FortisBC's internal systems only and not the purchase of load control devices for appliances at an approximate cost of $75 each. The lower end of the range reflects AMI vendors that have this capability as standard for no additional cost. The higher end reflects that if this were a required function, the number of vendors would be limited which may have upward pressure on the price of the AMI system.

13 – Reflects capital costs only and not required operating expenses which are outlined in the response to BCUC IR No. 2 Q9.4.

27.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q15.5.3, p. 36

Cost Review

Q27.1 On a confidential basis, would FortisBC please provide the expected value of their AMI equipment components and installation costs?

A27.1 The requested information has been filed in confidence with the Commission.

28.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q16.5, p. 38

Estimate of Cost Review

Q28.1 Please confirm that the AMI consultant that assisted in the estimating process was the same consultant who reviewed the project scope, vendor estimates and internal FortisBC costs.

A28.1 Confirmed.

Q28.2 Please confirm that no external review of the project scope and cost estimate has been conducted using an independent third party that has not been directly involved in the project scope and cost estimates.

A28.2 Confirmed.

29.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q16.6, p. 39

AMI Internal Costs

Q29.1 As the internal cost is only an AACE Class Four, would FortisBC please supply the estimate magnitude of cost for this item and its percentage cost of the total project cost?

A29.1 As stated in response to BCUC IR No. 1 Q28.4 (Exhibit B-2), internal costs account for approximately $2.8 million or 9 percent of the total project cost.

Q29.2 What is the estimate upper amount for this FortisBC internal costs and what is the adder to the $31.342 million?

A29.2 If the estimate of internal costs was in the upper range of +60 percent, the costs would be $4.5 million which is an increase of $1.7 million. However, FortisBC believes the estimating accuracy to be -10%/+20%, representing costs of $3.2 million which would represent an incremental cost of approximately $0.6 million.

30.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q16.10, p. 47

AMI Unit Costs

Q30.1 Please submit in confidence.

A30.1 The response has been filed in confidence with the Commission.

31.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q16.10, p. 47

Network Infrastructure Costs

Q31.1 Please submit in confidence.

A31.1 The response has been filed in confidence with the Commission.

32.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q17.3.4, p. 53
Battery Replacement Costs

Q32.1 Did FortisBC include or not include battery costs in their estimate of costs?

A32.1 FortisBC included the initial cost of all components within the AMI enabled meter. As vendors will be required to deliver on technology that either has no battery or has a battery life of 25 years, no future additional costs were added into the estimate.

Q32.2 If not what is the adder to the rate impact calculations?

A32.2 As stated in the response to BCUC IR No. 2 Q32.1, no incremental costs are required.

33.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q33.2, p. 83

Contingency

Q33.1 In tabular format, please provide the list of items that were identified in Section 7.3 of the Application and their corresponding amounts to a total of $2,764,000.

A33.1 Contingency factors during the deployment of the AMI technology are as follows:

Table A33.1: Risk Contingency Costs

Factor	Total Cost ($000)
Batch failures of the AMI meters	168
Large scale communications failure	204
Data transfer issues	86
General project contingency	2,306
Total	**2,764**

Q33.2 Please confirm that "Market Conditions" have been address as an identifiable item in the Contingency.

A33.2 Confirmed. Market conditions have been incorporated into the general project contingency.

34.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC Q33.2, p. 83

Escalation (including inflation) analysis

Q34.1 In tabular format, please provide the list of items that were identified in Exhibit B-2 FortisBC response to BCUC IR. No. 1, Q27.3 and their corresponding amounts to a total of $763,000.

A34.1 FortisBC believes that the reference to BCUC IR No. 1 Q33.2 (Exhibit B-2) should be to Q16.12, which shows a total escalation in capital costs of $763,000. Labour and vehicle cost escalations are components of the overall capital cost escalation of 2.0 percent per year. The escalation rates provided in the response to BCUC IR No. 1 Q27.3 (Exhibit B-2) related to FortisBC's internal resources for operating costs and were not used for escalation of capital costs because these are expected to be a fairly small component of the capital budget. The Composite Depreciation Rate, Composite CCA Rate, and Income Tax rates do not affect the capital cost of the project.

35.0 Reference: Exhibit No. B-2, FortisBC Response to Wait Q3, p. 1

AMI Unit Costs

Q35.1 Please submit in confidence.

A35.1 The requested items have been filed in confidence with the Commission.

NARUC/FERC Collaborative
on
Demand Response

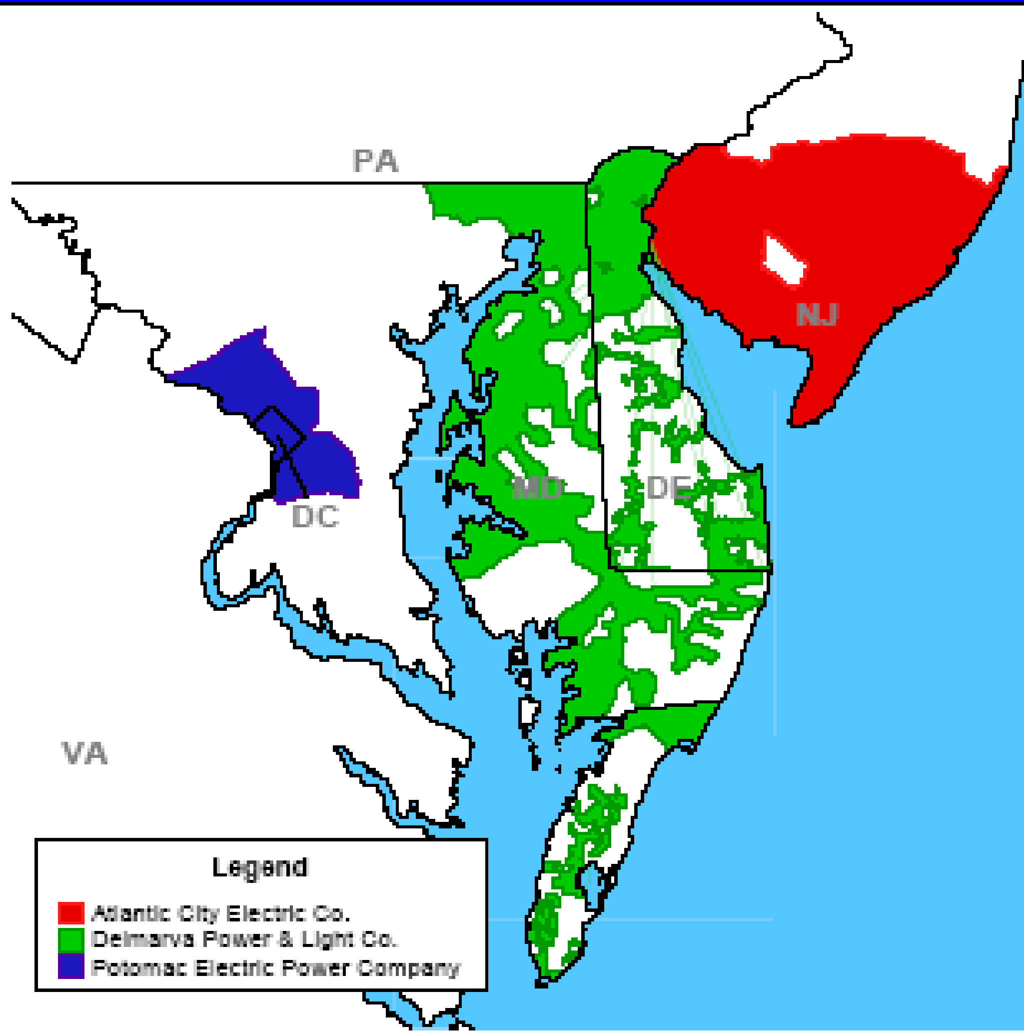
Pepco and Delmarva Power
Blueprint for the Future Filings

J. Mack Wathen

July 15, 2007

Appendix 8.1a

Combined Service Territory



Motivation for Pepco and Delmarva Blueprint Filings

- **Higher Regional Energy Costs**
  - Blueprint can help reduce and stabilize electricity costs

- **Impact of Energy Use on the Environment**

Our Customers tell us they want…

- Reasonable energy costs
- Reduced volatility in price
- Reliable service
- Environmental stewardship
- Information to make choices

PHI Blueprint Filings

- Delaware Delmarva Power Filing -- February 9, 2007
  - Commission Established Working Group Process
- Maryland Delmarva Power Filing – March 21, 2007
  - Commission Established Working Group Process
- Maryland Pepco Filing – March 21, 2007
  - Commission Established Working Group Process

PHI Blueprint Filings (continued)

- District of Columbia Pepco Filing – April 4, 2007
  - Commission Established Regulatory Case
  - "PowerCents DC" Smart metering pilot underway

- Each Blueprint Plan Includes:
  - AMI Universal Deployment for all PHI Electric/Gas Distribution Customers
  - Utility Provided Energy Efficiency Programs
  - Utility Provided Demand Response Programs
  - Each Plan Specific to Each Jurisdiction

- New Jersey Atlantic City Electric Filing – Planned for later in 2007
- Other components of Blueprint include Distribution System Automation; conversion of our 2000+ vehicle fleet to alternative fuels including hybrids, bio-diesel and other technologies; "Energy Know How" tools

Key PHI Blueprint Initiatives

- Energy Efficiency/Conservation Programs
  - Reduce Annual Electricity Use
- Demand Response Programs
  - Reduce Summer Peak Electricity Demand
- Advanced Metering Infrastructure
  - Improve Distribution System Operation
  - Improve Customer Service
  - Provide Interval Consumption Data through Remote Readings
  - Support Demand Response through Dynamic Pricing and Direct Load Control Technology Capability
  - Support Small Renewable Generation/Plug-In Vehicles

DSM Program Selection Process

- Commercially Available DSM Measure
- Applicable to Mid-Atlantic Market
- Screened for Cost-Effectiveness using All Ratepayers Test (ART)
  - Avoided Energy Prices Derived from MD SOS Prices
  - Avoided Capacity Prices Derived from Cost of New Generation Entry and Regional Transmission Constraints
- Approx. 370 DSM Measures Screened for Cost-Effectiveness
  - 65% Projected to be Cost-Effective Under ART
- Additional Measures Would Pass if Societal Test Used and Value of Reduced Negative Externalities Estimated
- Pepco/Delmarva Power DSM Programs Intended to be a Starting Point for Utility Specific Collaboratives
  - Measures Expected to be Cost-Effective Packaged into Programs

Delmarva Power/Pepco Recommended Utility DSM Programs

- **General Awareness Campaign** – Customer DSM Education/Marketing Effort

- **Residential Programs**
  - Home Performance w/Energy Star: Home Audit Based Program
  - HVAC Efficiency: High Efficiency Central AC/HP and Training Program
  - Lighting/Window AC Program: Compact Florescent Lighting and High Efficiency Window Units Program
  - Smart Stat: Remotely Controllable Programmable T-stat Central AC/HP Program

Delmarva Power/Pepco Recommended Utility DSM Programs (continued)

- **Non-Residential Programs**
  - Building Commissioning and O&M: Consulting/Engineering Services to Improve Efficiency of Buildings
  - HVAC Efficiency: High Efficiency HVAC Equip. up to 30 Tons and Contractor Training
  - Prescriptive: Energy Efficiency Measure Incentives for Electric Motors and Lighting
  - Custom Incentive: Site Specific Efficiency Measures
  - Smart Stat: Remotely Controllable Program T-Stat Program
  - Internet Platform: Web-based Platform to Facilitate Participation in PJM Demand Response Market

Pepco and Delmarva Power DSM Forecast Impact After Three Year Initial Implementation

- Residential
  - 85.8 MW Peak Demand Reduction
  - 135,906 MWh Annual Energy Reduction
  - 265,459 Participants
  - 1,245,648 DSM Measures
- Non-Residential
  - 234.5 MW Peak Demand Reduction
  - 433,124 MWh Annual Energy Reduction
  - 37,032 Participants
  - 5,429,706 DSM Measures

AMI Benefits Include…

- Remote Meter Reading
  - Eliminates Need for Meter Reader and improves accuracy
  - Supports Enhanced Customer Service Capabilities
  - Customer Specific Load Research Data
- Demand Response
  - Communicates w/Demand Response Enabling Technology
  - Supports Dynamic Pricing Options
  - Enhances Customer Control Over Monthly Bills through Detailed Consumption Data
- Distribution System Monitoring
  - Improves Distribution System Design, Reliability, and Performance
- Distribution System Asset Management
  - Outage Reporting
  - Increased Accuracy of Repair Crew Dispatch
- Remote Service Disconnect
  - Reduces Utility Service Visits

Proposed Cost Recovery

- **Bill Stabilization Adjustment**
  - Distribution Rate Decoupling Mechanism Removes Utility Financial Disincentive to Offer/Support DSM
  - Only Applicable to Distribution Portion of Bill
  - Proposed in Delmarva Power/Pepco Current Distribution Base Rate Cases
- **DSM Surcharge**
  - Non-Bypassable Distribution Surcharge
  - Rate Class Differentiated
  - 5 Year Recovery of DSM Costs
  - Interest on Unrecovered Costs at Utility Allowed Rate of Return
  - Similar to Maryland DSM Surcharge in Existence During the 1990s
- **Proposed AMI regulatory approach**
  - Timely Recovery of AMI Capital Costs Over 15 Year Period to Reflect Expected Equipment Life
  - Accelerated Cost Recovery of Existing Meters Over 3 to 5 Year Period
  - Recovery of Demand Response Smart Thermostat Capital Cost Over 15 Year Period

Blueprint Path Forward

- Pepco and Delmarva Power are Prepared to Begin the Implementation of their Blueprint Plan Now
- The Plan Will:
  - Help Customers Manage Higher Energy Costs
  - Help Reduce Overall Regional Wholesale Electricity Market Prices
  - Lessen Burden on Increasingly Constrained Regional Transmission
  - Reduce Future Power Plant Air Emissions
  - Improve Distribution System Operations
  - Improve Utility Customer Service
  - Take Advantage of New Technologies
- Implementation Delay will Lengthen the Period Before these Benefits are Available to Consumers

Quantifying Demand Response Benefits In PJM

Prepared by

The Brattle Group
44 Brattle Street
Cambridge, MA 02138

Prepared for

PJM Interconnection, LLC and the

Mid-Atlantic Distributed Resources Initiative (MADRI)

January 29, 2007

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1.0 EXECUTIVE SUMMARY

There is widespread recognition of the need to institute demand response (DR) in today's electricity markets. During critical peaks in the demand for electricity, such as during summer heat waves, wholesale electricity prices can rise to their highest levels. Most end-use customers are on fixed retail rates that do not reflect spot market signals, causing inefficient outcomes in which they continue to use energy in low-value applications even when the wholesale price of electricity is very high. The recent Energy Policy Act of 2005 includes provisions that call upon states and utilities to evaluate and implement demand response programs to help address this situation.[1] California has initiated comprehensive regulatory proceedings about demand response, advanced metering and dynamic pricing. Other states, including Hawaii, Idaho, Illinois, Missouri and New Jersey, are conducting pilot programs with a variety of innovative demand response rates and technologies.

For these reasons, the PJM Interconnection, LLC (PJM) and the Mid-Atlantic Distributed Resources Initiative (MADRI) are interested in developing DR resources as a meaningful contributor to the power markets within the PJM region.[2] In order to inform the development of prudent policies and investments, they have sought to quantify the benefits of demand response. PJM, working with the MADRI state commissions, thus issued a request for proposal (RFP) for this study quantifying the impact of demand curtailment on wholesale prices and customer costs in the MADRI states and in the broader PJM region.

In accordance with the RFP, this study uses a simulation-based approach to quantify the market impact of curtailing 3% of load in the BGE, Delmarva, PECO, PEPCO, and PSEG zones during the top twenty 5-hour price blocks in 2005 and under a variety of alternative market conditions. We performed simulations using the Dayzer model developed by Cambridge Energy Solutions (CES), and using data provided by CES, PJM, and public sources. By comparing simulations with and without curtailments, we obtained the following results:

- Curtailing 3% of each selected zone’s super-peak load, which reduces PJM’s peak load by 0.9%, yields an energy market price reduction of $8-$25 per megawatt-hour, or 5-8% on average, during the 133-152 hours in which curtailment occurs in at least one zone. The range depends on market conditions.
- Assuming all loads (i.e., customers or their retail providers) are exposed to spot prices, the estimated price reductions could benefit non-curtailed loads in MADRI states by $57-$182 million per year. The potential benefits to the entire PJM system amount to $65-$203 million per year.
- The market impact in each zone would be substantially smaller if it curtailed its load in isolation from the other zones. By the same token, the market impact would be larger if

[1] Section 1252 of Energy Policy Act of 2005. See Public Law No: 109-58.

[2] MADRI was established in 2004 by the public utility commissions of Delaware, the District of Columbia, Maryland, New Jersey and Pennsylvania, along with the U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA), Federal Energy Regulatory Commission (FERC) and PJM Interconnection.

more than five zones implemented DR programs or if greater amounts of DR participation were achieved.

This study also provides a rough estimate of benefits to DR program participants. Program participants enjoy two sources of benefits:

- The first is an energy benefit from curtailing load of much lesser value than the price of energy on the spot market. These benefits were estimated to be $85 to $234 per megawatt-hour or $9 to $26 million per year based on the results of the Dayzer simulations and some simplifying assumptions on the economic value customers placed on their curtailable load. Without making those assumptions, the range of benefits widens to $1 to $36 million.
- The second major source of benefit to program participants is the reduction in capacity needed to meet reserve adequacy requirements for a load shape that has been modified by reducing the peaks. A very rough estimate of this long-term capacity benefit is $73 million per year for curtailment of 3% of load in the five zones. More rigorous analyses of these participant benefits would be needed, along with an assessment of the costs of equipment and administration of demand response programs, in order to fully evaluate the net benefits to participants.

It is important to note that this study has not quantified several additional categories of benefits of DR. These include enhanced competitiveness of energy and capacity markets, reduced price volatility, the provision of insurance against extreme events that have not been captured in the scenarios considered, the option to curtail some load in the volatile real-time market, reduced capacity market prices, and deferred T&D costs. In addition, because this study focuses on curtailments to day-ahead schedules, it does not capture the additional benefits that real-time demand response can provide by mitigating the effects of unexpected events such as increases in load, generation outages, and transmission outages.

It is equally important to note that this study does not consider several secondary effects that could offset the benefits to non-curtailed loads. Consumers may shift load to other hours, which could somewhat increase prices in those hours. Our estimates of price effects would also be offset partially by a more muted response of customers on real-time pricing, as a consequence of the lower market prices. Moreover, reduced energy prices and reductions in the demand for capacity could accelerate the retirement of old capacity and/or delay the construction of new capacity, leading to an eventual increase in energy prices relative to our estimated price reductions. In addition, assuming that energy and capacity markets reach competitive equilibrium, a reduction in energy market prices and hence energy margins would likely trigger an increase in capacity prices as suppliers raise capacity bids to recover their going-forward fixed costs. We have not analyzed where and when such competitive equilibrium conditions can be expected, how long it will take for the energy market impact to be offset by capacity effects, or how complete the offset is likely to be.

Ultimately, the long-term benefits will be determined by the extent to which adding DR to the resource mix lowers total resource costs. Although the energy and capacity-related effects quantified in this study are related to resource costs, a comprehensive analysis of total resource costs, including an assessment of the likely technology mix of future capacity and DR, is a question that has not been addressed in this study.

Our conclusions are summarized in Table 1.

Table 1. Annual Benefits from 3% Load Reduction in the top 100 Hours in 5 MADRI Zones

	Quantified Benefits in MADRI States	Quantified Benefits in Other PJM States	Unquantified Benefits	Caveats
Benefits to Non-Curtailed Load	**$57-182 Million** (energy only) **(5-8%** price reduction in curtailed hours)	**$7-20 Million** (energy only) **(1-2%** price reduction in curtailed hours)	• Capacity price decrease due to reduced demand; • Enhanced competitiveness in energy and capacity markets; • Real-time vs. day-ahead; • Value of reduced volatility; • Insurance against extreme events; • Avoided T&D costs.	• Probably significantly offset in long-run equilibrium as capacity and capacity prices adjust; "long-run" might not be so long. • Load shifting and demand elasticity offest some benefit in short-term.
Energy Benefits to Curtailed Load	**$9-26 Million** (**$85-234/MWh** price reduction in curtailed hours)	**n/a**	n/a	• Based on simplifying assumptions regarding the value of load that is curtailed.
Capacity Benefits to Curtailed Load	**$73 Million** (assuming **$58/kW-Yr)**	**n/a**	n/a	• Based on generic long-run cost of avoided capacity; • Ignores costs of equipment and DR program administration.
Total Annual Benefits	**$138-281 Million**	**$7-20 Million**	• Additional benefits to non-curtailed load could be large.	• Includes both the solid economic efficiency gains to curtailed load and the less robust benefits to non-curtailed loads.

2.0 STUDY SCOPE AND ORGANIZATION OF THIS REPORT

This study focuses primarily on estimating the direct impact of reductions in peak loads on energy market prices. Under tight market conditions, a small reduction in demand can result in a large reduction in spot prices because the supply curve in the high demand range is steeply sloping upwards. Changes in spot prices not only affect spot transactions, but also influence the pricing of longer-term transactions to the extent that market participants anticipate such changes in spot prices. With lower market prices, demand reductions will tend to lower payments to generators and reduce overall energy costs to load, relative to the less efficient situation in which demand is unable to respond to market signals. This study estimates the magnitude of price reductions and resulting benefits to non-curtailed loads caused by demand curtailments during peak periods, as described in Section 3.

The study also includes an estimate of the benefits to curtailed loads, since these important benefits could be informed by the simulations already performed. Curtailed loads receive both an energy benefit and a capacity benefit. The energy benefit derives from eliminating marginal uses of energy that are of lesser value than the marginal cost of generation. The capacity benefit derives from the fact that curtailment of peak loads “flattens” the load shape, thus reducing the total amount of capacity needed to meet peak load. The methodology for estimating benefits to curtailed loads is described in Section 4.

Given the tight time frame within which this study was performed, we did not analyze several categories of additional benefits and offsetting factors. These benefits and offsets are discussed qualitatively in Section 5 of this report and may be analyzed in greater depth as part of a “Phase II” study by MADRI or PJM.

Section 6 discusses the conclusions from this study.

3.0 ENERGY MARKET IMPACTS AND RESULTING BENEFITS TO NON-CURTAILED LOADS

3.1. Overview of Methodology

In order to estimate short-term price impacts of demand curtailment, PJM, working with the MADRI states, issued a request for proposal (RFP) for a study simulating the PJM market with and without demand curtailments in peak hours. The RFP outlined the study methodology that was developed through the MADRI stakeholder process. The study was to estimate the LMP reductions from curtailing demand in the BG&E, Delmarva, PECO, PSEG, and PEPCO control zones, by three percent (3%) in the top twenty (20) five-hour (5-hr) priced blocks[3] that occurred during 2005 under various load conditions and fuel prices: an actual peak load case (AP), a weather-normalized case (N), a high peak load case (HP), a low peak load case (LP), a high fuel case (HF), and a low fuel case (LF). For each case, the direct impact of demand curtailment on load's locational marginal prices (LMPs) and financial transmission rights (FTRs) revenues was to be calculated.

The Brattle Group's analysis was conducted using the state-of-the art locational power market simulation model, "Dayzer." Dayzer is well-suited to this study because of its capabilities to simulate actual markets accurately. In addition to capturing the basic elements of supply (i.e., every generating unit and its characteristics), demand (every load bus in every load zone), and transmission (i.e., the actual load flow used by PJM), Dayzer also captures the daily and hourly fluctuations in market conditions that can cause changes in prices and transmission congestion. The data structures in Dayzer are synchronized daily with publicly available datasets from PJM and other sources by CES, including data regarding actual unit outages, hourly dynamic ratings of transmission lines, actual daily transmission outages, actual hourly interchanges with neighboring RTOs, and actual daily variations in spot prices for fuels. As a result, Dayzer can accurately replicate actual LMPs, including the LMPs during the super-peak hours when curtailments would occur.

We estimated the impact of demand curtailment on day-ahead power prices in the PJM market. The analysis was performed in the following four steps:

1. Develop an accurate representation of the PJM market in 2005 by refining the Dayzer model's input data, and by calibrating and validating the model outputs against actual market data.
2. Construct and simulate reference cases against which the impact of demand curtailments will be assessed.

[3] These particular specifications were developed through the MADRI stakeholder process to represent a range of DR programs that could reduce load during critical-peak periods. DR programs can include real-time pricing programs, critical-peak pricing programs, and various forms of curtailment programs, including direct load control of residential air conditioners, curtailable and interruptible rate programs for commercial and industrial customers, and cash-incentive based programs for customers who curtail load when called upon for economic reasons.

3. Construct and simulate curtailment cases in which each selected zone's load is curtailed by 3% in the top twenty (20) five-hour (5-hr) blocks from the corresponding reference case.
4. Quantify price impacts and benefits to non-curtailed load (net of changes in FTR revenues) in each curtailment case relative to each corresponding reference case.

It is important to note that this methodology estimates the market impact of day-ahead (DA) curtailments, not real-time curtailments, because Dayzer (and other similar models) simulates the day-ahead market more realistically than the real-time market. Such models are almost never used to simulate real-time markets because they lack the last minute surprises that cause real-time uncertainty and price volatility. Rather, these models commit and dispatch according to a load forecast and a known set of available resources that do not vary between commitment (day-ahead) and actual dispatch (real time). Such certainty does not produce the volatility that characterizes the real-time market. Therefore, this study does not capture the additional value of an option to curtail demand on a real-time basis. In real time, prices can spike due to unexpectedly high load and forced generation and transmission outages, which can create scarcity and may force the RTO to rely on high-cost blocks of emergency energy that have been bid into the market.

3.2. Refinement of Input Data; Calibration and Validation of the Model

3.2.1. Refinements to Input Data

The Dayzer model takes as inputs all of the elements of supply, demand, and transmission in the PJM Interconnection, with more limited data regarding neighboring systems. All data necessary for simulating historical periods are provided by CES, but in order to represent the 2005 PJM market as accurately as possible, we worked closely with PJM staff to update and refine nearly all categories of input data, as summarized in Table 2 below. Given these refinements, the model is replicating the fundamentals of supply, demand, and transmission as closely as reasonably possible based on data that is publicly available (except for unit outages, which are confidential).

Table 2: Data Sources and Refinements

Category of Inputs		Sources and Refinements
Supply	Capacity Online	Compared data in Dayzer to confidential unit data provided by PJM and made changes where necessary to achieve consistent aggregate capacity in each zone, by technology.
Supply	Generator Characteristics	Heat rates and emissions rates from *Energy Velocity*, based on CEMS and FERC filings. For each technology type, used generic assumptions for heat rate shapes, variable O&M costs, minimum-up-time, startup costs, and other characteristics.
Supply	Fuel Prices	*Gas* : ICE Daily spot prices for each Transco Zone + local distribution charges *Oil* : NYMEX spot prices for FO2, FO6 + historical transportation differentials *Coal* : Based on EIA-423's and NYMEX spot prices (data for all fuels provided by CES).
Supply	Emission Allowance Prices	Daily spot prices from Cantor Fitzgerald (data provided by CES).
Supply	Generator Outages	Confidential unit outage schedules from PJM.
Supply	Imports/Exports from Outside PJM	Actual day-ahead scheduled hourly interchanges at each interface point (data provided by CES).
Supply	Unit Bids	Calibrated unit bids to publicly available bid data, by region and by technology type
Demand	2005 Hourly Load by Zone	Implemented actual 2005 real-time load in each zone; used real-time load as proxy for load expectations underlying the day-ahead market (data provided by CES).
Demand	Operating Reserve Requirements	Actual hourly PJM requirements (data provided by CES).
Transmission	Load Flow Case (represents transmission system and load distribution in each zone)	PJM's load flow case used for its 2005 FTR auction.
Transmission	Flow Limits	Actual hourly limits on reactive interfaces. For thermal limits, conformed to actual flow limits posted at http://oasis.pjm.com/doc/PJM_Line_Ratings.txt.
Transmission	Transmission Outages	Actual line outages downloaded from PJM (provided by CES).

Source and Notes:
* "CES" refers to Cambridge Energy Solutions, the provider of the Dayzer software, CES propriety data, and daily downloads of data from the PJM website.
** *Energy Velocity* is part of Global Energy Decisions Inc's *Velocity Suite*.

3.2.2. Calibration of Bids

Because the theoretical marginal cost bids developed for use in Dayzer are based on estimated parameters, we calibrated the Dayzer marginal cost bids to capture additional factors incorporated into actual bids. Marginal costs for each unit in Dayzer are given by the following equation:

Marginal costs = Estimated incremental heat rates × Index-based spot fuel prices +
Estimated emissions rates × Allowance prices +
Generic assumptions for variable operating and maintenance costs (VOM).

Some cost components are only approximated and may not be sufficiently accurate under certain conditions. For example, heat rates and corresponding emissions do not vary based on ambient temperature and plant conditions; generic VOM assumptions do not consider how bidders may allocate periodic maintenance costs over their expected operating hours; and zonal fuel prices may be insufficiently granular. Actual unit cost-based bids can also include opportunity costs related to environmental constraints or special operating constraints and must conform to the Market Monitoring Unit's Cost Determination Task Force Standards.[4]

The Dayzer bids were calibrated using the publicly available PJM Daily Energy Bids Data.[5,6] This dataset provides unit-level price bids that PJM publishes with a 6-month lag. Although the publicly available data does not identify individual units by name, we were able to determine each unit's approximate location within PJM based on the date when each unit first appears in the dataset. Units in PJM-East have been present in the dataset since June 2000 (except for new units); those in APS, ComEd, AEP, Dayton, Duquesne, and Dominion have appeared on or around the dates that the respective regions joined PJM.

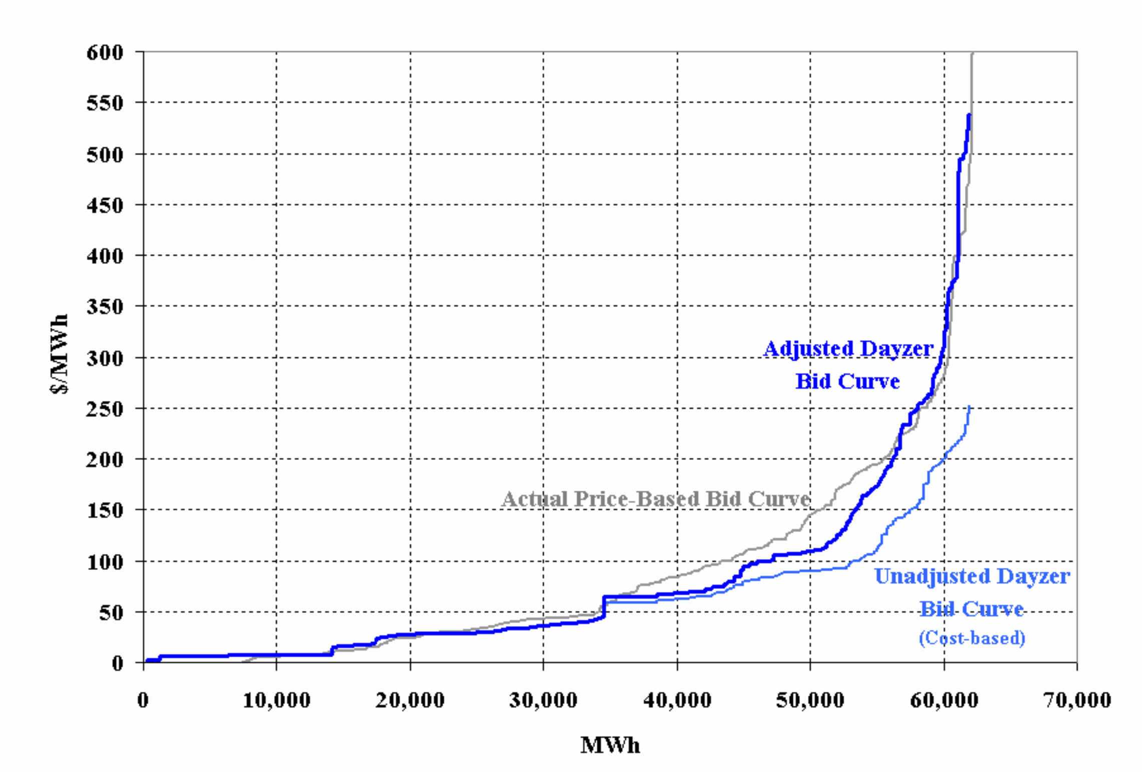
Figure 1 compares the initial cost-based bid curve for PJM-East to the adjusted bid curve and the actual price-based bid curve for one day, July 12, 2005. Similar adjustments were made for the other regions.

[4] *PJM Manual 15: Cost Development Guidelines* recognizes opportunity costs as costs incurred when "the provision of a product prevents the provision of another product with a higher value." For example, if a unit has only a limited number of annual run hours, and if the unit is dispatched as must run by PJM to relieve a transmission constraint, the opportunity cost of providing must-run output is the value associated with the foregone opportunity to supply energy during a higher valued time period. (See http://www.pjm.com/contributions/pjm-manuals/pdf/m15.pdf). These guidelines do not apply to price offers or to certain generation units installed between July 9, 1996 and September 30, 2003, which are exempt from cost-based offer caps. (See Section 6.5 of *Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.* at http://www.pjm.com/documents/downloads/agreements/oa.pdf.)

[5] Available at http://www.pjm.com/markets/jsp/bids-emarket.jsp.

[6] Note that constructing a PJM supply curve from these data assumes the absence of system or operational constraints and the absence of unit specific bid parameters, both of which would limit the in-merit availability of the offer blocks. The data set also does not indicate whether the bids represent cost or price based offers, or whether the offer listed was the offer upon which the units were or would have been committed in actual dispatch.

Figure 1. PJM-East Actual Bid Curve vs. Dayzer Bid Curves (July 12, 2005)



3.2.3. Model Calibration and Validation

The final Dayzer backcast of actual 2005 market conditions appears to be quite accurate, particularly during peak hours. As Table 3 shows, simulated PJM Eastern Hub prices are within $6 per megawatt-hour (3%) of actual day-ahead average prices during the top 100 hours and within $6 per megawatt-hour (6%) of the average price over all peak hours.

The accuracy of the Dayzer simulation is lower in shoulder and off-peak hours, possibly because of the remaining gap between adjusted Dayzer bids and actual bids in the $50-$200/MWh range of the PJM-East bid curve. Accuracy is also more limited in the Western zones of ComEd, AEP, Dayton, and Duquesne, where simulated prices are overstated in the top 300 hours. In addition, simulated prices are low in the Dominion service area, possibly because of high bids and under generation in the West, hence lower congestion on the West-East constraints that tend to have a disproportionate effect on prices in PEPCO and Dominion. Finally, a price spike is missing in PECO because Dayzer is not capturing the extreme congestion that occurred in August, 2005 on the Whitpain transformer between the 500 kV system and the PECO service territory.

Table 3. Differences Between Average Simulated Prices and Average Actual DA Prices

Region	Zone Name	Actual		Dayzer		Dayzer Minus Actual	
		Top 100 Hours	Jun-Sep Avg Peak	Top 100 Hours	Jun-Sep Avg Peak	Top 100 Hours	Jun-Sep Avg Peak
South	DOM	$181	$100	$151	$91	($31)	($9)
East	PEPCO	$212	$110	$207	$99	($6)	($11)
East	BGE	$200	$106	$191	$99	($8)	($7)
East	DPL	$193	$104	$200	$99	$7	($5)
East	AECO	$205	$111	$203	$106	($1)	($5)
East	PECO	$203	$106	$186	$96	($17)	($10)
East	METED	$192	$103	$199	$96	$7	($7)
East	PSEG	$189	$104	$187	$99	($2)	($5)
East	JCPL	$184	$101	$181	$94	($3)	($7)
East	RECO	$179	$100	$167	$87	($13)	($13)
East	PPL	$187	$101	$179	$92	($8)	($8)
East	PENELEC	$144	$83	$170	$80	$25	($3)
East	EASTERNHUB	$198	$105	$203	$99	$6	($6)
East	WESTERNHUB	$164	$91	$168	$84	$3	($8)
Mid	APS	$164	$88	$186	$78	$22	($10)
Mid	DUQ	$118	$65	$142	$59	$24	($6)
West	AEP	$128	$72	$136	$63	$8	($8)
West	DAY	$123	$69	$136	$62	$13	($7)
West	AEPDAYTONHUB	$126	$70	$137	$63	$11	($8)
West	AEPGENHUB	$121	$68	$133	$60	$11	($8)
West	COMED	$127	$71	$137	$63	$10	($8)
West	NILLINOISHUB	$126	$71	$137	$63	$11	($8)

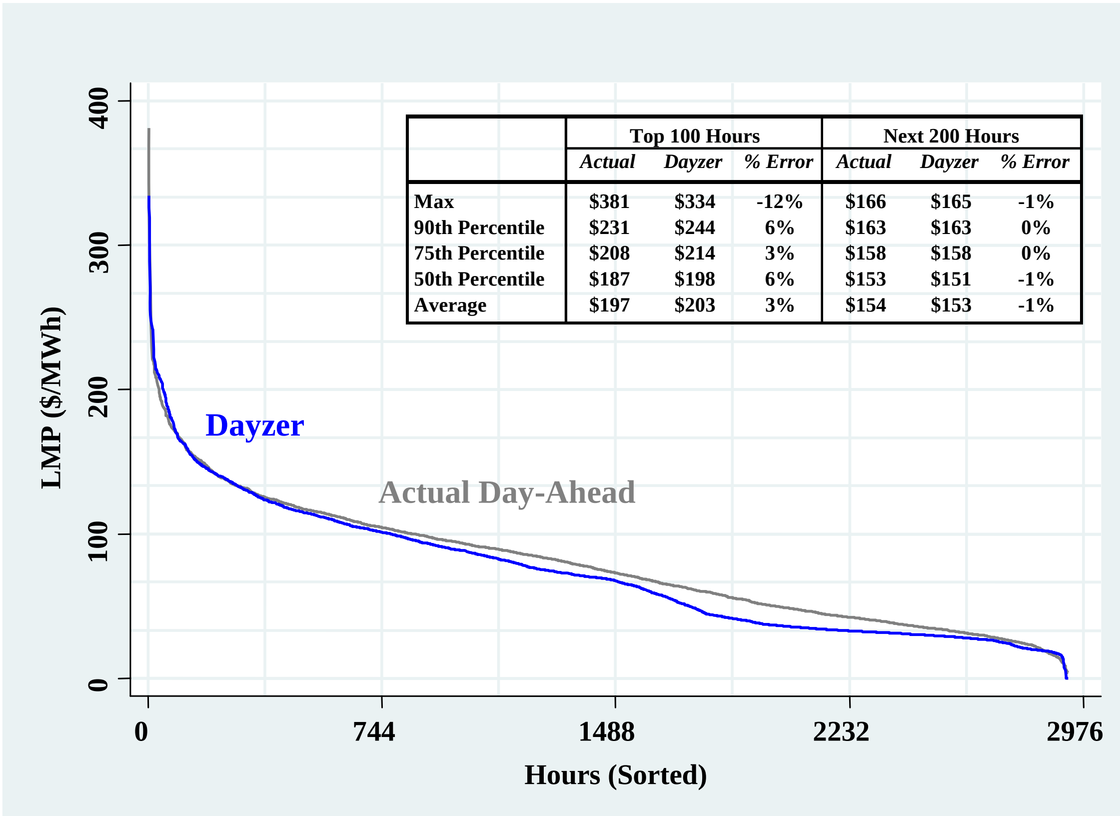
Source and Notes:
Actual LMPs from Global Energy Decision Inc.'s *Velocity Suite*, August 2006 data release.
"Peak" defined as hour ending 7 through 22 Monday through Friday, except for NERC holidays.

Importantly, however, the Dayzer prices are the most accurate during the top few hundred hours, including the super-peak periods on which this study focuses. The price duration curves in Figure 2 show close replication of actual day-ahead prices during the top hours.

It is theoretically possible to calibrate Dayzer more precisely, but the precision would still be limited by the quality and the lack of specificity in the public bid data. Furthermore, even if the actual daily bids for every unit were available, replicating actual day-ahead prices exactly would be nearly impossible for a variety of reasons, including:

- Actual unit startup costs and operating constraints could be more constraining than the standard assumptions in Dayzer.
- The real-time load used in the model is only a proxy for expected day-ahead loads; there will always be differences due to market participants' imperfect forecasts.
- Imports from outside PJM can set market prices in PJM, but Dayzer represents them as non-price-setting fixed injections in order to replicate actual day-ahead scheduled flows.
- The model is not capturing some dynamic transmission limits and operating procedures for which public data was not available.
- Dayzer assumes a time-invariant distribution of load among buses in each load zone.

Figure 2. Comparison of Eastern Hub LMP Duration Curves (June-September, 2005)



	Top 100 Hours			Next 200 Hours		
	Actual	*Dayzer*	*% Error*	*Actual*	*Dayzer*	*% Error*
Max	**$381**	**$334**	**-12%**	**$166**	**$165**	**-1%**
90th Percentile	**$231**	**$244**	**6%**	**$163**	**$163**	**0%**
75th Percentile	**$208**	**$214**	**3%**	**$158**	**$158**	**0%**
50th Percentile	**$187**	**$198**	**6%**	**$153**	**$151**	**-1%**
Average	**$197**	**$203**	**3%**	**$154**	**$153**	**-1%**

3.3. Development of Reference Cases

Based on the 2005 "backcast" simulations described above, *The Brattle Group* constructed and simulated reference cases against which the impact of demand curtailments were to be assessed. In order to capture a range of possible market conditions, we adopted the 2005 backcast as the "actual peak" (AP) reference case and created several alternative reference cases with loads and fuel prices that differ from the actual peak.

3.3.1. The Normalized (N) Case

The most atypical attributes of the 2005 market were the hurricane-induced fuel price disruptions and the load shape. *Brattle* constructed a Normalized Case by adjusting both of these variables.

Load was normalized by starting with a load profile for each zone in the year 2002, which was a year that PJM staff deemed to be "typical". Then each zone's hourly load was multiplied by the demand growth implicit in the differences between the 2002 weather-normalized peak load and the 2005 weather-normalized peak load. This methodology produced a peak load that was approximately 4% higher than the 2005 weather-normalized peak reported by PJM,[7] consistent

[7] 2006 PJM Load Forecast Report, Table B1, p. 29.
Available at http://www.pjm.com/planning/res-adequacy/downloads/2006-pjm-load-report.pdf.

with the fact that cooling-degree days and peak loads in the 2002 base-year were above normal.[8] Hence, the "Normalized" Case is actually above normal for 2005 and might be considered more nearly representative of a normal 2007-08, when load is projected to be 3.2-4.9% higher[9] without major capacity additions.[10]

To approximate "normal" natural gas and distillate oil (FO2) prices, one-year NYMEX futures traded in 2006 for delivery in the same month of 2007 were used. For example, the Henry Hub gas price used for July 26, 2005 in the normalized case is given by the price of futures traded on July 26, 2006 for delivery in July 2007. The resulting normalized prices during the June through September period were on average at $8.3/MMBtu for Henry Hub and at $14.9/MMBtu for FO2, somewhat higher than currently-traded futures for delivery in July, 2007 of $7.6/MMBtu for gas and $11.9/MMBtu for FO2.[11]

No residual oil (FO6) futures are traded on NYMEX, so normalized FO6 prices were derived from futures prices for crude oil. First, a relationship between FO6 and crude spot prices was identified through a regression model, and then the regression coefficients were used to project normalized FO6 prices based on futures prices for crude oil. The resulting average FO6 price was $7.0/MMBtu for June through September.

To normalize emission allowance prices, an average of actual daily spot prices was applied across the entire June through September 2005 study period. The resulting prices were $2,435/ton and $831/ton for nitrogen oxide (NOx) and sulfur oxide (SOx) respectively.

3.3.2. The High Peak (HP) and Low Peak (LP) Cases

The High Peak (HP) and Low Peak (LP) cases were constructed from the Normalized (N) case, but with load inflated or deflated to reflect one-in-twenty-year conditions. Twenty-year conditions were determined by comparing actual peaks to weather-normalized peaks for each year from 1984 to 2004.[12] Actual peaks differed from normalized peaks by -8% to +5%, which was approximated as +/- 6%.[13] This factor was applied to scale up/down the hourly loads from the Normalized case to arrive at the High/Low Peak cases.

[8] Available at http://www.ncdc.noaa.gov/oa/documentlibrary/hcs/hcs.html#52overview.

[9] PJM projects a 1.6% annual growth rate in peak load, amounting to a 3.2% and 4.9% increase over the normalized 2005 load in 2007 and 2008, respectively. See the 2006 PJM Load Forecast Report, page 1.

[10] According to the 2005 PJM State of the Market Report, p.133, total installed capacity in PJM as of Dec 31, 2005 was 163,471 MW. This is projected to increase by 0.6% and 1.5% in 2007 and 2008 respectively. Available at http://www.pjm.com/planning/res-adequacy/downloads/20061228-forecasted-reserve-margin-correction.pdf.

[11] Current prices from NYMEX on January 29, 2007 are available at http://www.nymex.com; FO2 is assumed to have a heat content of 139,000 Btu per gallon.

[12] 2005 PJM Load Forecast Report. Available at http://www.pjm.com/planning/res-adequacy/downloads/2005-load-forecast-report.pdf.

[13] As a point of reference, the PJM load during the extreme heat spell in July/August of 2006 exceeded the weather-normalized peak by 6.2%. 2006 hourly load data are available at http://www.pjm.com/services/system-performance/downloads/historical/2006-hourly_loads.xls. Weather normalized peaks are available at http://www.pjm.com/planning/res-adequacy/downloads/summer-2006%20-peaks-and-5cps.pdf.

3.3.3. The High Fuel (HF) and Low Fuel (LF) Cases

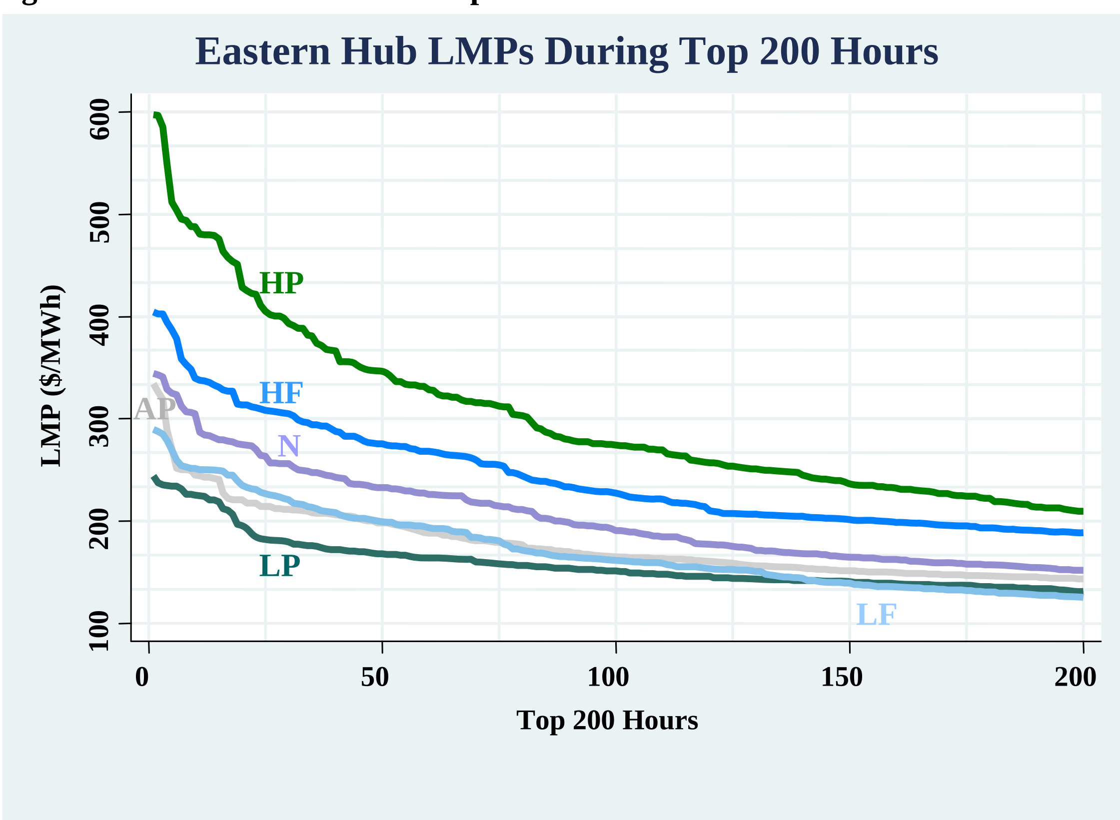
The HF and LF cases represent an 80% confidence interval around the 2007 forward prices for gas and oil, based on historical distributions describing the ratios of spot prices to 1-year forwards transacted one year prior. The 90th and 10th percentiles of these ratios were then applied to the normalized prices to yield the high and low prices, respectively. As a result, the average prices in the HF and LF cases are: \$10.1/MMBtu and \$6.4/MMBtu for Henry Hub, \$8.4/MMBtu and \$6.3/MMBtu for residual oil, and \$17.9/MMBtu and \$13.3/MMBtu for distillate oil.

NOx and SOx allowance costs were also varied because they tend to be related to fuel prices. In the HF case, NOx allowance prices were set at \$3,020/ton and SOx allowance prices at \$1,330/ton, corresponding to the highest daily prices observed in June through September of 2005. In the LF case, NOx allowance prices were set at \$2,050/ton and SOx allowance prices at \$745/ton, corresponding to the lowest daily prices observed in June through September 2005.

3.3.4. Simulation of Reference Cases

Each of the reference cases was simulated separately using Dayzer. Figure 3, below, shows that these cases span a large range of market conditions and prices.

Figure 3. Eastern Hub Prices in Top 200 Hours in Six Reference Cases



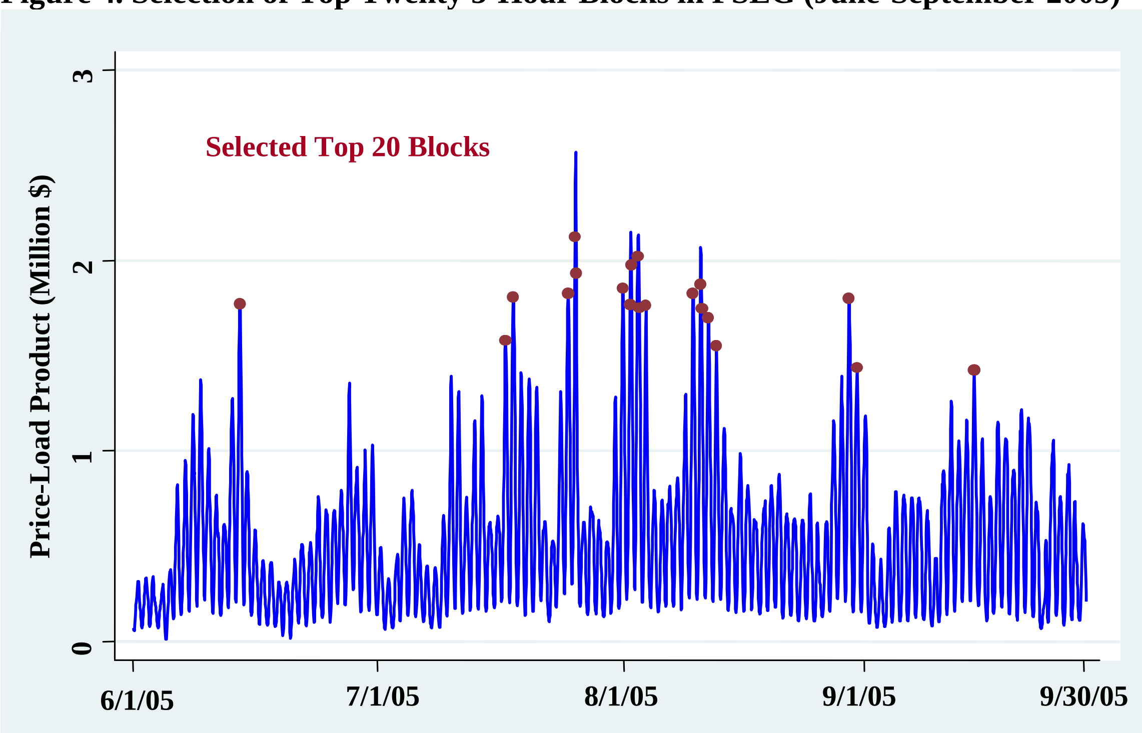
Notes: AP= Actual Peak; N = Normalized; HP = High Peak; LP = Low Peak; HF = High Fuel; LF = Low Fuel.

3.4. Development of Curtailment Cases

3.4.1. Identification of Top Twenty 5-Hour Blocks

One curtailment case was developed for each reference case, with all data inputs the same as the corresponding reference case, except for the hourly load, which was reduced by 3% in the top twenty 5-hour blocks in the five curtailment zones. The top blocks were selected based on the price-load product rather than price alone because reducing prices in an hour with high load benefits customers more than reducing prices by the same amount in an hour with low load.[14] The selection of top blocks was performed individually for each of the five zones. The red dots in Figure 4 below indicate the identified hours for the PSEG zone in the Actual Peak case; top blocks were selected similarly for the other four target zones and for all of the other cases.[15]

Figure 4. Selection of Top Twenty 5-Hour Blocks in PSEG (June-September 2005)



Notes:
The plot shows 5-hour moving averages of the hourly price-load products.
"Hourly price-load product" defined as Dayzer simulated LMP multiplied by real-time load in the corresponding hour.

[14] DR programs could be designed to target the highest priced hours rather than the highest price-load hours, but the results would be similar because of the high correlation between hourly prices and load.

[15] In actual 2005 market conditions, all of the top price-load blocks occurred in the summer, which enabled us to limit the simulation period to June through September.

3.4.2. Simulation of Curtailment Cases

Each curtailment case was constructed from the corresponding reference case, with hourly zonal loads reduced by 3% during the top blocks identified for each zone. It is important to note that the top blocks in one zone do not always coincide with those in another, so there are hours in which the load is reduced in only one zone. Moreover, even when 3% of load is curtailed in all five zones simultaneously, the combined curtailment in the five zones does not exceed 1,200 MW, which is only 0.9% of the peak load across all zones in PJM.

For the curtailment cases, we used the same unit commitment schedule as in the corresponding reference cases, but allowed combustion turbines to ramp down to zero. Holding unit commitment fixed was necessary in order to prevent the price "noise" normally produced by unit commitment from overwhelming the price reductions caused by curtailment. Unit commitment can be noisy because of the discrete choice nature of the problem (a unit is either on or off) and because of limitations in any commitment algorithm's ability to find the absolute optimum solution to the problem. With load curtailments of 100-1,200 MW (about the size of just a few units), the algorithm can produce a different unit commitment solution that changes prices substantially and misleadingly. Holding the unit commitment schedule constant avoids such noise.

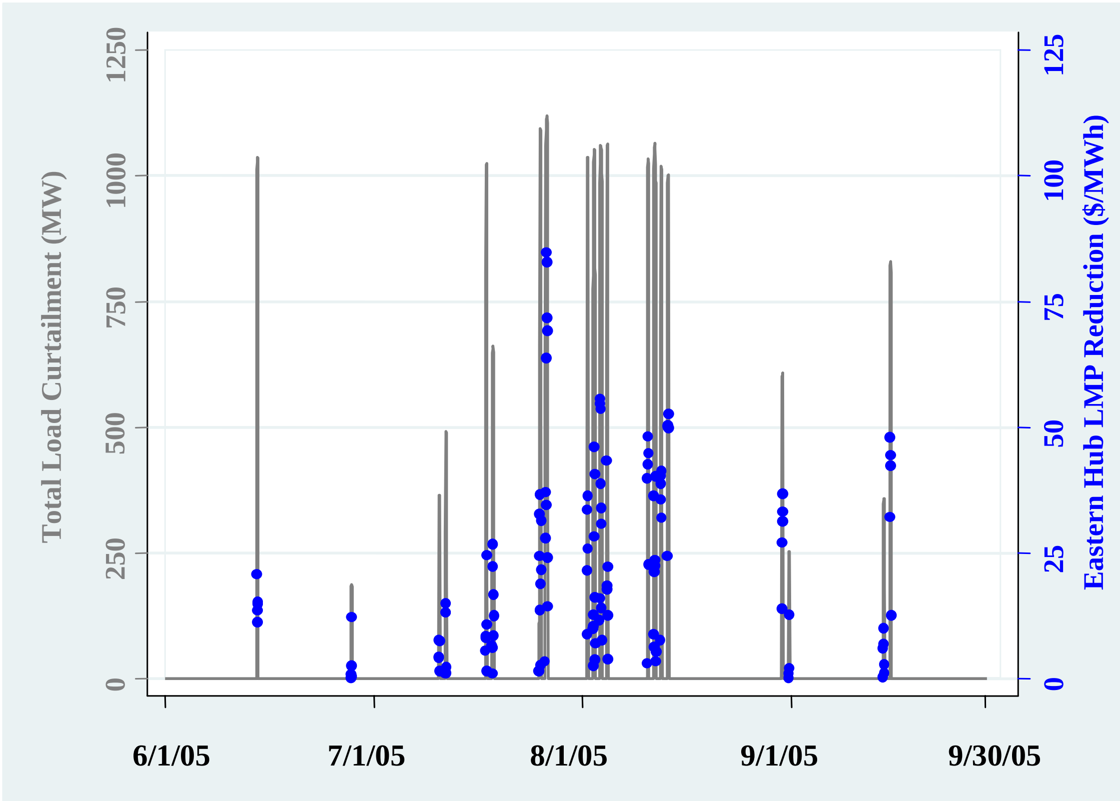
3.5. Estimation of Benefits to Non-Curtailed Loads

3.5.1. Direct Energy Price Impact

Comparing prices in the curtailment cases to those in the corresponding reference cases isolates the direct impact of load curtailment on prices. Figure 5 shows the hourly price impact on PJM Eastern Hub for the AP case. The blue dots, to be read against the right-hand y-axis, represent hourly price changes, while the grey lines, to be read against the left-hand y-axis, show the hourly quantities of curtailment driving the price reductions.[16] Similar illustrations of price impacts for the other cases are presented in Figures A2-A6 of the Appendix.

[16] These figures do not consider the additional benefits or offsetting effects that are discussed in Section 5.2.

Figure 5. Impact of Load Curtailment on Prices at PJM Eastern Hub (AP Case)



These results are also tabulated in columns A-D of Table 4, which shows that curtailing less than 2% of load in MADRI states reduces prices by $8-$25 per megawatt-hour (5-8%) during the 133-152 hours in which at least one zone's load is curtailed. The percentage decrease is relatively uniform across states, except in Delaware, where prices decrease by 6-12% because curtailment relieves very high shadow prices on the North Seaford transformer. Actual congestion in 2005 was not quite as high as it appears in Dayzer, so the simulated price impact in Delaware is likely somewhat overstated.

Table 4. Price Impacts and Benefits to Non-Curtailed Loads by State

	Weighted Average LMP Reduction		Average Load Curtailment		Average Residual Load (MW)	Gross Direct Benefits (Million $)	ARR Change (Million $)	Net Direct Benefits (Million $)
	($/MWh) [A]	(%) [B]	(MW) [C]	(%) [D]	[E]	[F]	[G]	[H]
Actual Peak (AP) Case ***(during 137 hours in which load is curtailed in at least one zone)***								
PA	**$11**	**5.8%**	**172**	**0.7%**	**25,514**	**$36.7**	**($6.3)**	**$30.4**
NJ	**$13**	**6.7%**	**211**	**1.2%**	**17,282**	**$29.7**	**($1.6)**	**$28.1**
DE	**$21**	**10.6%**	**57**	**2.2%**	**2,482**	**$7.3**	**($1.6)**	**$5.7**
MD	**$12**	**6.0%**	**259**	**2.0%**	**12,886**	**$20.8**	**($4.3)**	**$16.5**
DC	**$13**	**6.0%**	**41**	**2.2%**	**1,791**	**$3.1**	**($0.9)**	**$2.2**
MADRI Total	**$12**	**6.7%**	**740**	**1.2%**	**59,955**	**$97.5**	**($14.7)**	**$82.9**
Normalized (N) Case ***(147 hours)***								
PA	**$11**	**5.2%**	**167**	**0.6%**	**26,435**	**$42.4**	**($8.8)**	**$33.6**
NJ	**$14**	**6.4%**	**208**	**1.1%**	**17,954**	**$35.9**	**($1.6)**	**$34.3**
DE	**$27**	**11.9%**	**53**	**2.1%**	**2,537**	**$10.0**	**($2.7)**	**$7.2**
MD	**$15**	**6.4%**	**252**	**1.8%**	**13,501**	**$29.3**	**($6.1)**	**$23.2**
DC	**$17**	**7.1%**	**40**	**2.1%**	**1,877**	**$4.8**	**($1.3)**	**$3.5**
MADRI Total	**$13**	**7.1%**	**721**	**1.1%**	**62,304**	**$122.4**	**($20.5)**	**$101.9**
High Peak (HP) Case ***(133 hours)***								
PA	**$23**	**6.7%**	**195**	**0.7%**	**28,158**	**$84.5**	**($21.9)**	**$62.6**
NJ	**$26**	**8.0%**	**244**	**1.3%**	**19,152**	**$66.8**	**($2.4)**	**$64.5**
DE	**$37**	**10.4%**	**62**	**2.3%**	**2,668**	**$13.1**	**($1.2)**	**$11.9**
MD	**$24**	**7.4%**	**295**	**2.0%**	**14,277**	**$45.3**	**($7.2)**	**$38.1**
DC	**$25**	**7.8%**	**46**	**2.3%**	**1,984**	**$6.7**	**($1.4)**	**$5.3**
MADRI Total	**$25**	**7.9%**	**842**	**1.3%**	**66,238**	**$216.5**	**($34.0)**	**$182.4**
Low Peak (LP) Case ***(151 hours)***								
PA	**$7**	**4.3%**	**152**	**0.6%**	**24,936**	**$27.2**	**($7.9)**	**$19.3**
NJ	**$9**	**5.3%**	**191**	**1.1%**	**16,874**	**$22.8**	**($1.6)**	**$21.2**
DE	**$10**	**5.8%**	**48**	**2.0%**	**2,375**	**$3.5**	**($0.2)**	**$3.3**
MD	**$8**	**4.8%**	**230**	**1.8%**	**12,703**	**$15.8**	**($4.0)**	**$11.9**
DC	**$9**	**5.0%**	**36**	**2.0%**	**1,770**	**$2.4**	**($0.7)**	**$1.6**
MADRI Total	**$8**	**5.0%**	**657**	**1.1%**	**58,657**	**$71.7**	**($14.4)**	**$57.3**
High Fuel (HF) Case ***(135 hours)***								
PA	**$15**	**6.0%**	**182**	**0.7%**	**26,571**	**$53.6**	**($9.0)**	**$44.6**
NJ	**$19**	**7.3%**	**227**	**1.2%**	**18,040**	**$45.7**	**($1.6)**	**$44.0**
DE	**$32**	**12.0%**	**58**	**2.2%**	**2,533**	**$11.1**	**($2.6)**	**$8.5**
MD	**$19**	**6.8%**	**274**	**2.0%**	**13,504**	**$33.9**	**($6.0)**	**$27.9**
DC	**$21**	**7.5%**	**43**	**2.2%**	**1,877**	**$5.4**	**($1.3)**	**$4.1**
MADRI Total	**$18**	**7.6%**	**785**	**1.2%**	**62,524**	**$149.6**	**($20.6)**	**$129.1**
Low Fuel (LF) Case ***(152 hours)***								
PA	**$9**	**5.2%**	**160**	**0.6%**	**26,357**	**$36.3**	**($7.9)**	**$28.4**
NJ	**$12**	**6.8%**	**201**	**1.1%**	**17,835**	**$33.0**	**($1.9)**	**$31.1**
DE	**$23**	**12.4%**	**52**	**2.0%**	**2,520**	**$9.0**	**($2.5)**	**$6.5**
MD	**$13**	**6.6%**	**244**	**1.8%**	**13,456**	**$26.1**	**($5.5)**	**$20.6**
DC	**$15**	**7.2%**	**38**	**2.0%**	**1,874**	**$4.3**	**($1.2)**	**$3.1**
MADRI Total	**$12**	**7.3%**	**696**	**1.1%**	**62,042**	**$108.6**	**($19.0)**	**$89.6**

Notes:
[A] and [B]: LMP reduction is weighted by hourly residual load.
[F] = [A] x [E] x number of hours with at least one zone curtailed.
[G]: 97% of ARRs are allocated to non-curtailed loads; the remainder is allocated to curtailed loads.
[H] = [F] + [G].
Benefits in zones spanning multiple states were allocated according to retail sales in June-September, 2005, from EIA form 826 reported in Global Energy Decisions Inc's *Energy Velocity*. Delmarva is allocated 28% to MD and 69% to DE (and 4% to VA). PEPCO is allocated 70% to MD and 30% to DC. APS, which has spillover price effects, is allocated 43% to PA and 19% to MD (and 29% to WV, 6% to VA, and 4% to OH).

It is likely that the price effect would be larger if more than 3% of load were curtailed in the five target zones or if all load in PJM participated in curtailment programs instead of just the BG&E, Delmarva, PECO, PEPCO, and PSEG zones, which represent only 27% of PJM's total peak load.

Alternatively, of course, if fewer customers participated in load curtailment programs, the benefits would be smaller. We simulated additional normalized curtailment cases in which only one of the five zones implemented demand curtailment. Comparison of columns G and H in Table 5 shows that the resulting price impact is less than half as big as in the case in which all zones curtailed demand. This finding suggests that the energy price impact of demand curtailment in a highly-interconnected network such as PJM has the attributes of a public good.[17] The collective customer benefits are greatest if everyone participates and curtailments are coordinated across zones.

Table 5: Market Impacts if Curtailment Occurs in Only One Zone (Normalized Case)

	Only One Zone Curtailed							All Curtailed
	Weighted Average LMP Reduction		Average Curtailed Load (MW)	Average Residual Load (MW)	Gross Benefits (Million $)	ARR Change (Million $)	Net Benefits (Million $)	Net Benefits (Million $)
	($/MWh) [A]	(%) [B]	[C]	[D]	[E]	[F]	[G]	[H]
BGE	**$6**	**2.8%**	**204**	**6,597**	**$4.2**	**($0.7)**	**$3.5**	**$12.1**
Delmarva	**$23**	**10.3%**	**115**	**3,706**	**$8.6**	**($4.2)**	**$4.4**	**$10.6**
PECO	**$9**	**4.2%**	**246**	**7,939**	**$7.0**	**($1.9)**	**$5.1**	**$14.9**
PEPCO	**$14**	**5.6%**	**193**	**6,255**	**$8.5**	**($3.1)**	**$5.4**	**$11.6**
PSEG	**$8**	**3.8%**	**306**	**9,902**	**$8.2**	**($1.1)**	**$7.0**	**$19.4**

3.5.2. Gross Benefits to Non-Curtailed Loads

Gross customer savings are calculated by multiplying the Reduction in Zonal LMP by the Residual Zonal Load in each curtailed hour, assuming all load is exposed to the price reduction observed in the simulations.[18] Total gross savings over all hours are tabulated in column F of Table 4, which shows gross benefits in the MADRI states of $72-$217 million per year.

The concept can be illustrated with a supply and demand curve, shown in Figure 6. An illustrative supply curve is shown in blue; the demand curve is idealized as a vertical line with no elasticity, representing the fact that most customers are not directly exposed to changes in spot prices, so their short-term demand is unresponsive to spot prices. Load curtailment is represented as a decrease in quantity demanded, from Q_1 to Q_2. This causes the spot price to drop from P_1 to P_2. The price savings to non-curtailed load[19] is given by area **bcde**, assuming

[17] However, in the long run, much of the energy benefit to non-curtailed loads could be offset by factors described in Section 5.2, reducing the public good attributes of demand curtailment.

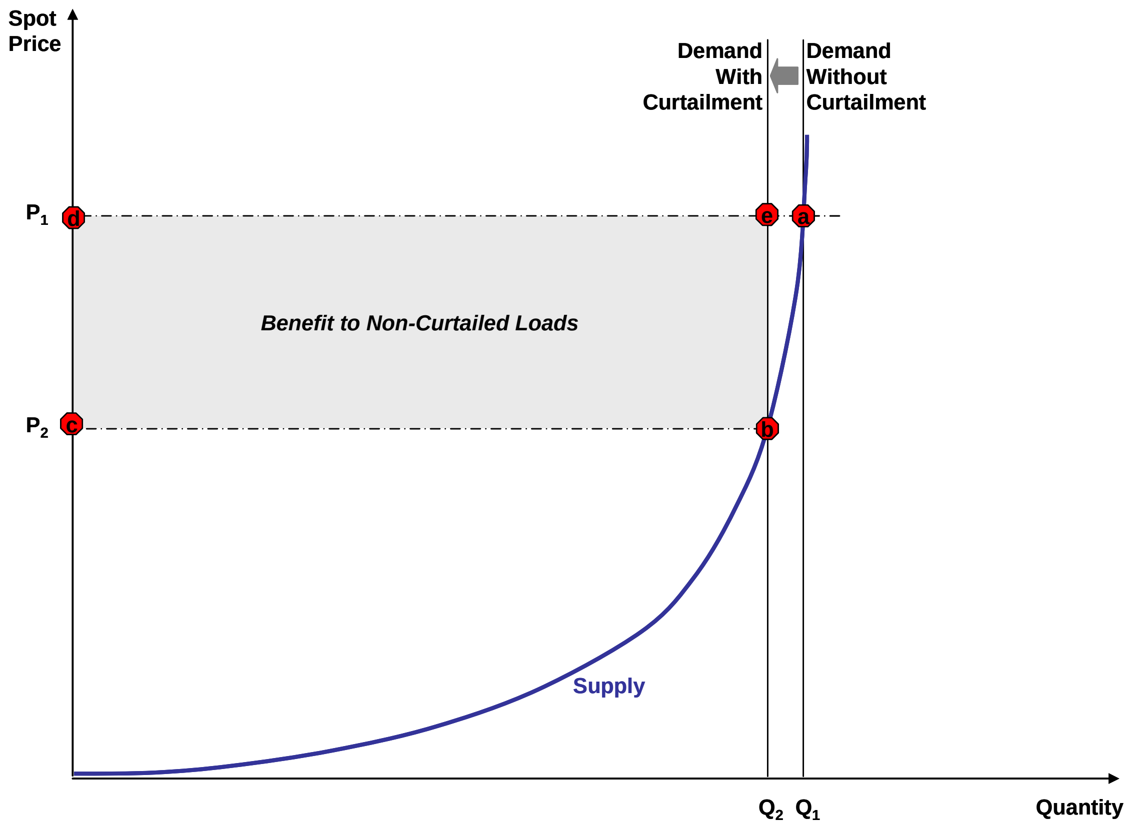
[18] The hourly change in LMP is multiplied by the hourly residual (i.e., non-curtailable) load rather than total load because load that has been curtailed does not consume energy and therefore does not benefit directly from the reduction in market prices.

[19] In this report, "load" refers generically to end-use customers and their retail providers. While benefits of unexpected changes in prices apply directly only to customers on real-time pricing and to the retail providers of other customers, the benefits of expected future price reductions apply to all end-use

none of the load is hedged though forward contracts with generators. To the extent that load is hedged through forward contracts with generators, the price savings would be reduced but only until the contracts expire.

Area **bcde** represents savings to customers, but it also represents a reduction in producer surplus relative to the less efficient situation in which demand is unresponsive to market signals. As such, this area is not a gain in economic efficiency. An efficiency gain does occur, but it accrues to the curtailed loads, as discussed in Section 4.1.

Figure 6. Conceptual Diagram of Direct Energy Benefits to Non-Curtailed Loads



3.5.3. Net Benefits to Non-Curtailed Loads

Gross benefits ignore changes in the value of FTRs. Net savings are calculated by subtracting the change in customers' FTR revenues from the gross savings. This calculation was performed using auction revenue rights (ARRs) rather than actual FTR holdings because ARRs reflect the customers' total allocated property rights to FTR revenues, whereas actual FTR holdings reflect auction outcomes and trading decisions. It was assumed that ARRs fully reflect all simulated

customers, assuming a competitive retail market and/or competitive wholesale provision of standard offer service in which rates reflect wholesale market costs.

changes in associated FTR revenues, as if bidders in the FTR auctions were able to fully anticipate the effect of demand curtailment programs on FTR revenues and bid accordingly.

The ARR revenues were calculated by multiplying the volume of each ARR by the simulated hourly LMP differential between the associated source and sink locations. PJM provided the necessary confidential data on ARR allocations.

The results of these calculations are summarized in columns G and H of Table 4, which shows that the reduction in ARR revenues reduces the total gross benefits by 14-20% overall, and as much as 5-28% in Delmarva. The intuition behind these reductions is that the gross benefits calculation assumes incorrectly that all customers pay the LMP measured at the load zone, where prices tend to be most sensitive to load curtailments. In fact, the financial effect of ARRs/FTRs is to allow loads to pay the LMPs at their generation sources, which tend to be lower and less sensitive to curtailments than the load LMP. The net measure of benefits accounts for this difference.

Netting out the reduction in ARR revenues, the benefits to non-curtailed loads in MADRI states becomes $57-$182 million per year, as shown in column H of Table 4. Outside of the MADRI states, spillover price effects produce an additional $7-$20 million in net benefits, for a total of $65-$203 million in net benefits to non-curtailed loads throughout PJM, resulting from less than 1% demand reduction in just 100 hours in five zones. More detailed results of zonal benefits and PJM total benefits are presented in Tables A1-A6 of the Appendix.

4.0 BENEFITS TO CURTAILED LOADS

4.1. Energy Benefits

Participants in curtailment programs save money by eliminating load that they value less than the spot price for energy.[20] We estimate these benefits to be $9-$26 million per year based on the results of the Dayzer simulations and some simplifying assumptions on the economic value customers place on their curtailable load. (Without making those simplifying assumptions, the range of benefits widens from $9-$26 million to $1-$36 million).

The concept is illustrated in Figure 7, which is similar to Figure 6, but with an illustrative “underlying demand curve” added. The underlying demand curve represents customers’ reservation prices for delivered energy, which would be the relevant market demand curve if all customers were on real-time pricing programs.[21] With most customers instead on fixed retail prices that do not reflect spot prices, their demand is completely inelastic with respect to spot prices; the market demand curve is distorted into a nearly vertical, inelastic curve, corresponding

[20] Even if the customer is not ordinarily exposed to spot prices, eliminating low-value load creates value. Curtailment programs can provide various mechanisms for customers to capture some of this value.

[21] The exact height and shape of the demand curve would also depend on the way in which transmission and distribution and other charges vary with consumption.

to the "Demand Without Curtailment" line in Figure 7. Curtailment programs add some elasticity to the demand curve, albeit more crudely than real-time pricing programs. The market demand curve becomes the dark black line labeled "e-g-f-h", such that demand is slightly lower when spot prices are high enough to trigger curtailment. Segment "f-g" represents the customers' marginal values of curtailable load.

The benefits to curtailed loads (which might be shared between the customer and their retail provider or curtailment provider) are given by area **aefg**, excluding any necessary equipment costs and the costs of administering the curtailment program. Area **abgf** represents the efficiency gain from not using expensive resources that are more valuable than the curtailable load. Area **abe** represents an increase in consumer surplus and a corresponding decrease in producer surplus. Note that area **bcde** is also labeled in this diagram in order to clarify the differences between the benefits to curtailed loads and benefits to non-curtailed loads. While there is an actual efficiency benefit enjoyed by curtailed loads (as well as an increase in consumer surplus), the consequential increase in consumer surplus to non-curtailed loads is entirely matched by a decrease in producer surplus.

Figure 7. Conceptual Diagram of Energy Benefits to Curtailed Loads

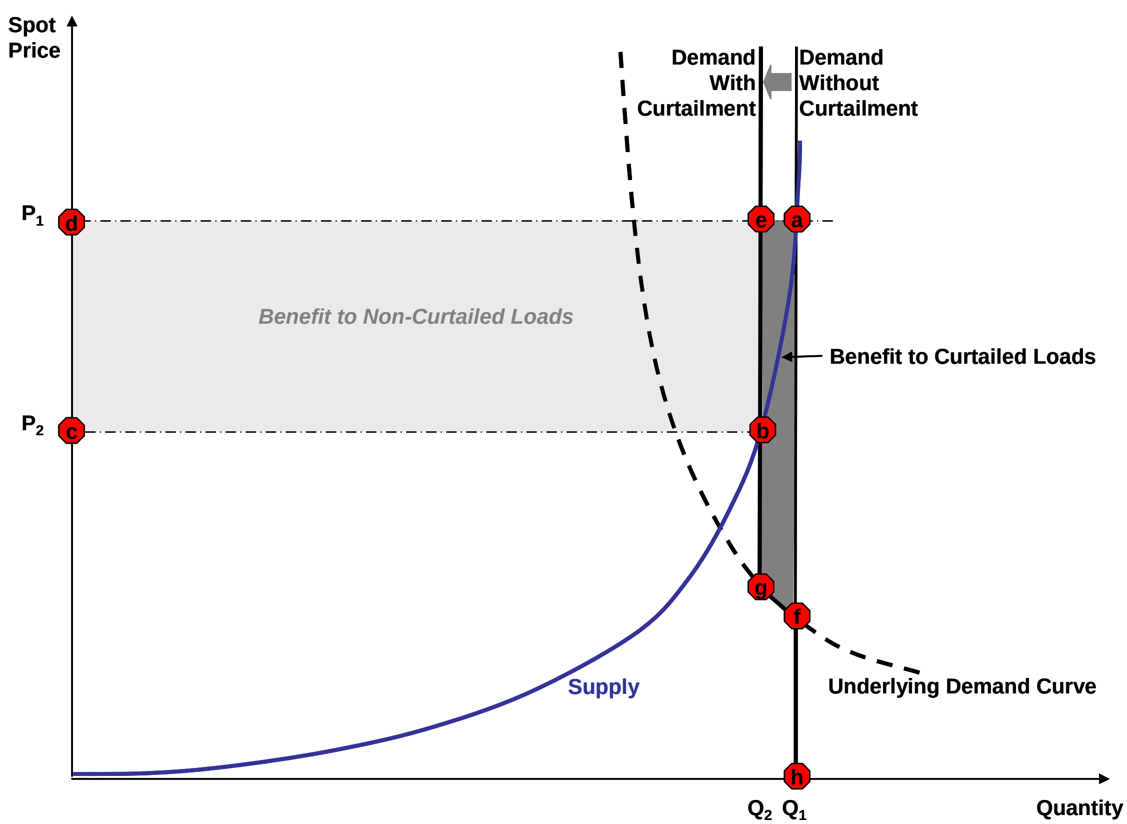


Figure 7 provides a framework for quantifying the energy benefits to curtailed loads, and the Dayzer simulations provide points *a*, *b*, and *e*. *Brattle* made some simplifying assumptions to estimate and bound the price levels of *f* and *g*. The lower bound for *f-g* is zero when customers value their curtailable load at zero, for example if customers have been over-air conditioning to the point that building occupants are uncomfortable but not thinking to turn up their thermostats until the curtailment program triggers their interest. The upper bound for *f-g* must be the post-curtailment spot price, P_2, or else the assumed 3% curtailment was too high, such that customers value their curtailed load more than the spot price. An intermediate value can also be estimated by assuming that *f* is given by the minimum retail rate among customer classes, based on the theory that customers consume energy until the marginal value of their least valuable kilowatt-hour equals their retail rate, and the customers with the lowest retail rates have the lowest value marginal uses of energy, and thus are most likely to voluntarily curtail load. Finally, line *f-g* is traced backward from *f* by assuming a typical short-run value of -0.1 for the price elasticity of demand[22] and enforcing that *f-g* does not rise above P_2.

Table 6 summarizes the energy savings to curtailed loads for each reference case. Columns B, C, and D show per megawatt-hour savings corresponding to the lower, intermediate, and upper estimates, respectively. Columns E through G report net savings adjusted for ARR changes. Across the six reference cases, participant savings by the intermediate estimate range from $9 to $26 million.

[22] A Department of Energy report summarizes various estimates of own-price elasticity that range from -0.28 to -0.01. Available at http://www.oe.energy.gov/DocumentsandMedia/congress_1252d.pdf.

Table 6. Energy Benefits to Curtailed Load by State

	Average Curtailed Load (MW) [A]	Benefits to Curtailed Loads ($/MWh)			Benefits to Curtailed Loads (Million $)		
		Lower Bound [B]	Intermediate Estimate [C]	Upper Bound [D]	Lower Bound [E]	Intermediate Estimate [F]	Upper Bound [G]
Actual Peak (AP) Case							
PA	**236**	**$15**	**$114**	**$178**	**$0.4**	**$2.7**	**$4.2**
NJ	**289**	**$15**	**$73**	**$183**	**$0.4**	**$2.1**	**$5.3**
DE	**78**	**$19**	**$127**	**$190**	**$0.2**	**$1.0**	**$1.5**
MD	**355**	**$13**	**$111**	**$189**	**$0.5**	**$3.9**	**$6.7**
DC	**56**	**$12**	**$111**	**$194**	**$0.1**	**$0.6**	**$1.1**
MADRI Total	**1,014**	**$15**	**$102**	**$185**	**$1.5**	**$10.4**	**$18.8**
Normalized (N) Case							
PA	**246**	**$18**	**$149**	**$213**	**$0.4**	**$3.7**	**$5.2**
NJ	**306**	**$18**	**$100**	**$211**	**$0.5**	**$3.1**	**$6.5**
DE	**79**	**$26**	**$155**	**$218**	**$0.2**	**$1.2**	**$1.7**
MD	**371**	**$18**	**$137**	**$216**	**$0.7**	**$5.1**	**$8.0**
DC	**58**	**$18**	**$140**	**$223**	**$0.1**	**$0.8**	**$1.3**
MADRI Total	**1,060**	**$18**	**$131**	**$214**	**$2.0**	**$13.8**	**$22.7**
High Peak (HP) Case							
PA	**259**	**$34**	**$259**	**$323**	**$0.9**	**$6.7**	**$8.4**
NJ	**324**	**$31**	**$198**	**$310**	**$1.0**	**$6.4**	**$10.1**
DE	**83**	**$42**	**$280**	**$343**	**$0.3**	**$2.3**	**$2.8**
MD	**392**	**$28**	**$235**	**$314**	**$1.1**	**$9.2**	**$12.3**
DC	**62**	**$25**	**$243**	**$326**	**$0.2**	**$1.5**	**$2.0**
MADRI Total	**1,120**	**$31**	**$234**	**$318**	**$3.5**	**$26.2**	**$35.6**
Low Peak (LP) Case							
PA	**230**	**$10**	**$105**	**$169**	**$0.2**	**$2.4**	**$3.9**
NJ	**290**	**$11**	**$58**	**$168**	**$0.3**	**$1.7**	**$4.9**
DE	**74**	**$12**	**$103**	**$166**	**$0.1**	**$0.8**	**$1.2**
MD	**350**	**$9**	**$90**	**$169**	**$0.3**	**$3.2**	**$5.9**
DC	**55**	**$8**	**$87**	**$170**	**$0.0**	**$0.5**	**$0.9**
MADRI Total	**999**	**$10**	**$85**	**$169**	**$1.0**	**$8.5**	**$16.8**
High Fuel (HF) Case							
PA	**246**	**$23**	**$191**	**$255**	**$0.6**	**$4.7**	**$6.3**
NJ	**306**	**$24**	**$142**	**$253**	**$0.7**	**$4.4**	**$7.7**
DE	**78**	**$31**	**$198**	**$261**	**$0.2**	**$1.6**	**$2.0**
MD	**370**	**$22**	**$178**	**$257**	**$0.8**	**$6.6**	**$9.5**
DC	**58**	**$21**	**$178**	**$262**	**$0.1**	**$1.0**	**$1.5**
MADRI Total	**1,059**	**$23**	**$172**	**$256**	**$2.5**	**$18.2**	**$27.1**
Low Fuel (LF) Case							
PA	**244**	**$16**	**$113**	**$177**	**$0.4**	**$2.8**	**$4.3**
NJ	**306**	**$16**	**$66**	**$175**	**$0.5**	**$2.0**	**$5.4**
DE	**78**	**$23**	**$120**	**$183**	**$0.2**	**$0.9**	**$1.4**
MD	**371**	**$16**	**$100**	**$178**	**$0.6**	**$3.7**	**$6.6**
DC	**58**	**$16**	**$103**	**$186**	**$0.1**	**$0.6**	**$1.1**
MADRI Total	**1,058**	**$16**	**$95**	**$178**	**$1.7**	**$10.0**	**$18.8**

Notes:
[E], [F], [G]: Benefits are net of changes in ARR value.
[B] = [E] / ([A] x 100 Hours). Similar formula applies for [C] and [D].

4.2. Capacity Benefits

Customers who agree to have their load curtailed during peak periods flatten the load shape of the market overall. This reduces the amount of generation capacity needed to meet reserve adequacy requirements and avoids the need to build peaking plants to serve just a few hours of (curtailable) peak load. This benefit will be enjoyed by program participants in the form of reduced capacity payments or demand charges, assuming that curtailable load is dependably curtailable and "counts" as a capacity resource or that it is not required to purchase installed capacity (ICAP) in order to comply with resource adequacy requirements. A rough measure of such a benefit is the $58/kW-yr levelized cost of new capacity that PJM has used to set its capacity deficiency payments.[23] Applying $58/kW-yr to the 1,101 MW reduction in peak load in the Normalized Case plus an avoided reserve margin of 15% yields a $73 million annual benefit to participating loads.[24] Benefits would be nearly proportionately higher if more peak load were curtailed. Clearly, there is substantial value available, but that value can be captured only to the extent that adequate DR programs are in place.

Capacity benefits could be quantified more rigorously by forecasting capacity prices for each zone and over time, based on PJM's new Reliability Pricing Model (RPM).[25] Although most of PJM currently has a surplus of capacity today, causing low capacity prices, any zones suffering from a shortage of capacity (including imports) would have correspondingly high capacity prices.

In the long term, a reasonably unbiased expectation is for all market areas to eventually reach equilibrium. On that timescale, capacity prices might not necessarily be $58/kW-yr, which is based on a new combustion turbine's fixed costs, including levelized capital costs. It is likely that the technologies that set capacity prices (e.g. their characteristics, costs, and expected energy margins) will change over time, particularly if new technologies and resource options develop, for example if DR resources become available more widely.

[23] PJM's Capacity Deficiency Rate is currently set at $160/MW-day (= 58.4 $/kW-Yr) based on the all-in levelized cost of a combustion turbine. (See Schedule 11 of the PJM Tariff at.http://www.pjm.com/committees/tac/downloads/20050829-item-5a-dsr-schedule-11.pdf).

[24] PJM requires a reserve margin of 15%. See *Summer 2006 PJM Reliability Assessment*, May 24, 2006.

[25] Available at http://www.pjm.com/committees/working-groups/pjmramwg/pjmramwg.html.

5.0 FACTORS NOT QUANTIFIED IN THIS STUDY

5.1. Benefits not Quantified

Important benefits of demand curtailment that have not been quantified in this study include enhanced market competitiveness, reduced price volatility, the provision of insurance against extreme events, the option to curtail some load in the volatile real-time market, reduced capacity market prices, and deferred T&D costs.

Enhanced Market Competitiveness

Many market observers have noted that, particularly during high-load periods, electricity markets suffer from structural problems that increase the incentive and ability for generators to exercise market power, including the fact that most customers are not exposed directly to spot prices, so they have no incentive to reduce even their lowest-value consumption when spot prices spike to $1,000 per megawatt-hour. Because of this regulatory construct, the market demand curve is almost completely inelastic. Expanding DR programs, including curtailment programs, would increase the elasticity of demand and thereby increase the competitiveness of the market. Simple game-theoretic models suggest that doubling the elasticity of demand – not an overly-ambitious goal, given the nascence of DR programs – would enhance competitiveness as effectively as a 50% reduction in market concentration would. Enhanced competitiveness could result in lower energy prices and lower capacity prices both in the short term and the long term.

Reduced Price Volatility

Many customers are risk-averse and value rate stability, for example because they need to be able to forecast their costs accurately for budgeting purposes. Yet retail rates can fluctuate in response to spot prices (for customers on real-time pricing) or expected wholesale prices (for other customers). To the extent that demand curtailment reduces volatility in the spot market, it improves rate stability for at least some customers. Our estimated benefits to non-curtailed loads, which are based on reductions in average prices, are incomplete measures of value because they do not account for the value of reducing the price *variance* faced by customers.

Insurance Against Extreme Events

The observation that benefits of demand curtailment in the High Peak Case exceed those in the Normalized Case more than the benefits in Normalized Case exceed those in the Low Peak Case suggests that demand curtailment has disproportionately more value under tighter market conditions. This is the reason for analyzing multiple scenarios instead of analyzing a single normalized scenario. However, most studies, including ours, analyze only a small number of plausible scenarios. There are many possible events that, even though fairly unlikely individually, would likely reduce the risk of high-cost outcomes and could add disproportionately to the overall probability-weighted value of curtailment. Such events include the coincident outages of major generators and transmission lines or extreme heat waves occurring in shoulder months when many generators are on maintenance. The value of demand curtailment could be quantified more completely by simulating such extreme, low-probability events.

Real-Time Curtailments

Dayzer and other similar models lack surprises in demand and supply conditions and the resulting price volatility that characterizes real-time markets.[26] Therefore, the simulated prices are more comparable to day-ahead prices, and this study must be considered an analysis of day-ahead curtailment programs. It does not capture the higher value of being able to curtail demand in the more volatile real-time market, when market conditions can become tight unexpectedly.

A recent analysis by PJM demonstrates the potentially large market impact of real-time curtailment.[27] PJM estimated that load reductions during the heat wave in August of 2006 reduced real-time prices by more than $300 per megawatt-hour during the highest usage hours, estimated to be equivalent to more than $650 million in payments for energy. This impact was very large for several reasons: demand reductions reached 2,000 MW (compared to approximately 1,100 MW in this study), they occurred in real-time, and because of the particular way PJM modeled the effect of curtailment. PJM simply re-ran its actual real-time software with 2,000 MW (that had actually been curtailed day-ahead) added back to the load in real time, without having committed additional capacity to serve that additional load. This left the modeled real-time market with insufficient capacity, forcing PJM's analysis to rely on very high-cost generation. Nevertheless, PJM's analysis suggests that load curtailment can have the greatest price impact when the curtailable resources are "dispatchable" in real-time under unexpectedly tight market conditions, such as when load has been under-forecast or when multiple generators trip offline.

Capacity Market Benefits to Non-Curtailed Load

The effects of demand response on energy prices are often discussed, but the potential effects on capacity prices are rarely mentioned. Demand response could reduce capacity prices by reducing peak loads and therefore reducing the demand for capacity, as determined by PJM's resource adequacy requirements. If the demand for capacity is reduced, then the capacity market could clear at a lower price, particularly if the demand reduction shifts the market balance from a capacity scarcity to a capacity surplus. Any resulting change in capacity price would apply to the entire non-curtailed load, yielding a potentially very large benefit.

In the long run, when new physical capacity is needed, however, the capacity price is likely to be set by the long-run marginal cost of new capacity and will hence be less sensitive to small reductions in demand. Even then, capacity prices could be lower with demand response than

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[26] Although generator outages, transmission outages, and load spikes are included in the model, they do not occur as a surprise. The model commits capacity given advance knowledge of all market conditions.

[27] See http://pjm.com/contributions/news-releases/2006/20060817-demand-response-savings.pdf

without because the long-run capacity supply curve is not completely flat. The long-run capacity supply curve is likely to be slightly sloped because not all marginal new capacity has the same cost due to diversity of site characteristics, technology and plant configurations, and developers' cost structures.

Delay of Transmission and Distribution Investments

Reducing peak loads by 3% is comparable to two years of load growth on average and possibly much more in certain locations. In some circumstances, reducing peak loads could enable utilities to delay upgrading distribution transformers and other T&D equipment that is stressed by peak loads.

5.2. Offsetting Market Effects Not Quantified

This study provides quantitative estimates in response to the question posed by MADRI and PJM: What is the direct effect of demand curtailment on energy prices and resulting benefits to non-curtailed loads? However, there are several short-term and long-term offsets to the quantified benefits.

Short-Term Offsets

First, customers participating in DR programs might shift some of their curtailed load to other hours. Such load shifting could reduce the market impact of curtailment by increasing prices and emissions in non-peak hours. However, the level of offsets depends on how much and to which hours the customer shifts load. The offsetting effect is likely to be small if consumption is shifted to off-peak hours. Second, price reductions resulting from demand curtailment could dampen the extent to which other customers respond to high market prices. Customers on real-time prices limit their response when they see a decrease in spot prices. Since these dynamic interactions of prices and loads are not considered in our simulation analyses, prices could consequently increase slightly relative to our estimates until a new equilibrium of demand and supply is reached in response to these price changes.[28] (Note, however, that as the number of customers on real-time prices increases, the total demand response to high spot prices will increase, resulting in a larger overall reduction in peak demand and market prices.) Third, reductions in energy prices could result in some generators earning insufficient revenues to cover their bid costs, resulting in higher uplift payments. While the overall magnitudes of these offsets may be small, they reflect the dynamic interactions of demand and supply that are not explored in our more static market simulation analysis.

[28] Evidence of load shifting and real-time price responsiveness is provided in "Assessment of Customer Response to Real Time Pricing -- Task 2: Wholesale Market Modeling of New Jersey and PJM" by the Center for Economic & Environmental Policy, Edward J. Bloustein School of Planning and Public Policy at Rutgers University, November 11, 2005.

Longer-Term Offsets

To expect the estimated benefits to non-curtailed loads to persist is like assuming one could permanently reduce prices by building a particular power plant. In the long run, under a competitive market equilibrium, the new plant will likely displace another plant, leading to the same supply and demand balance and potentially the same market prices as if the particular plant had not been built.

Curtailable demand is similar to physical peaking capacity. In the long run, reduced market prices and the associated reduction in producer surplus could induce the retirement of marginal capacity and the delay of new capacity additions. Such a response could increase energy prices, partially offsetting some of the benefits to non-curtailed load that have been quantified in this study. These offsets could occur quickly if increased DR quickly induces plant retirements.

The estimated energy market benefit to non-curtailed loads is likely to be further offset by increases in capacity prices. To the extent that suppliers of marginal capacity expect to earn less in the energy market, they may bid higher prices into the capacity market in order to cover their fixed costs. For example, power plants that are candidates for retirement will stay online only if they expect to recover their fixed "to-go" costs through a combination of energy margins and revenues for providing ancillary services and capacity. Similarly, potential new entrants will build new capacity only if they expect to recover their long-run marginal cost of building and operating new capacity.[29] Hence, a reduction in energy margins must be expected to be offset by increases in capacity payments in the long run, assuming a competitive market equilibrium. Again, these "long-term" offsets may occur fairly quickly if expectations for reduced energy margins work their way quickly into bids for providing capacity.

It is possible to estimate capacity online and capacity prices in the short- to medium-term (i.e., 1-3 years), when the market is in a known deviation from equilibrium and any new capacity coming online is already under construction (retirement decisions are more difficult to predict). However, it is more difficult to foresee exactly how and when the population of generation capacity will change in the future, where new plants will be built, when boom-bust cycles in capacity will occur, what technology will set the price for capacity, and what capacity prices will be in the long-term future. Under such uncertainty, detailed analyses are less useful, and broad-brush assumptions become more necessary. The most economically defensible broad-brush assumption is not to ignore the possibility that capacity and capacity prices will change in response to increase DR – that would be to assume that generators would perpetually keep money-losing plants online, or that they would over-invest in new capacity, earning less than their cost of capital. An unbiased, standard economic assumption is that the market will reach an equilibrium in which generators earn their cost of capital, neither more nor less in expectations, such that there would be significant offsets to the energy benefits calculated from the static analysis of this study.

[29] See "Demand Response Is Important—But Let's Not Oversell (or Over-Price) It," Steven D. Braithwait, *The Electricity Journal*, Volume 16, Issue 5, June 2003, pages 52-64, for a discussion of the "dynamic effects of price expectations on generators' investment behavior."

Ultimately, the long-term benefits will be determined by the extent to which adding demand response to the resource mix lowers total resource costs. Although the energy and capacity-related effects quantified in this study are related to resource costs (such as the cost of a new peaking unit), a comprehensive analysis of total resource costs, including an assessment of the likely technology mix of future capacity and demand response resources, is a question that has not been addressed in this study. Adding DR to the long-term resource mix could, for example, lower the long-term marginal cost of capacity.

In any timeframe, a more comprehensive analysis would also have to consider the competitiveness effects discussed in Section 5.1. DR will have the greatest value in markets that are not in a competitive equilibrium because they are temporarily tight or in structurally less competitive market areas that may also suffer from barriers to entry. In such cases, demand curtailment could enhance the competitiveness of both energy and capacity markets. Indeed, the market impacts of demand curtailment are likely to be the greatest and most enduring not where markets are working well, but where competition is limited.

5.3. Environmental Implications

Demand reductions during periods of peak load could achieve environmental benefits by reducing generation of the dirtiest plants in load centers on the hottest, smoggiest days. However, this study has not attempted to estimate this environmental benefit of demand curtailment. In addition, offsetting shifts in load and generation are likely to consume most or all of the temporary savings.

The most important offset comes from shifts in the cap-and-trade markets. NOx and SOx emissions (and soon CO_2 in states that have signed the Regional Greenhouse Gas Initiative) are determined by the regulatory cap, such that a temporary decrease in emissions liberates allowances which could be used by others either locally or elsewhere in the regional/national cap-and-trade region.[30]

Similarly, some units' emissions are limited by maximum-run-hour constraints or by emissions limits imposed by their environmental permits. Reducing generation in one period could allow these units to run more in other periods if economic.

An additional offset occurs because some participants in curtailment programs do not actually curtail their load but instead run behind-the-meter distributed generation (DG), which could be dirtier than the market generation it displaces if it is not pollution-controlled. Moreover, if the DG units are less than 25 MW, they are not subject to the market-wide cap-and-trade program, so running DG could increase total market-wide emissions.

[30] See "Is Real-Time Pricing Green?: The Environmental Impacts of Electricity Demand Variance," Stephen P. Holland and Erin T. Mansur, The Center for the Study of Energy Markets (CSEM) at the University of California Energy Institute, August 2004. Holland and Mansur estimated the impact of reductions in "load volatility" on emissions, but they note that their estimated increases and decreases in emissions would not result in a net change in emissions where emissions are regulated by cap-and-trade programs (p. 26).

Even if there were no offsets, e.g., for mercury in the near term, a 3% reduction in generation in 1% of hours reduces total generation by only 0.03%, assuming, unrealistically, that there are no shifts in load to coal-dominated off-peak hours and no increases in consumption among price-responsive customers. The associated reduction in emissions would be similarly small. There would not be a disproportionate impact like there is with energy prices, which are affected by the extreme steepness of the bid offer curve in tight periods and the fact that the price reduction affects the entire market, not just the marginal generation.

6.0 CONCLUSIONS

This study demonstrates that even a modest 3% load reduction in each of five PJM zones' 100 super-peak hours, amounting to 0.9% of PJM's peak load, would have substantial energy and capacity market benefits to both curtailed and non-curtailed loads.

- Spot prices would be reduced by 5-8% during curtailed hours, resulting in a $57-$182 million short-term annual benefit to non-curtailed loads in the five MADRI states (adjusted for changes in ARR/FTR value). The system-wide benefits to PJM loads range from $65 to $203 million. More widespread participation in DR and deeper curtailments would result in even greater price impacts; less widespread participation results in substantially less benefit in each zone, suggesting that a regional approach to promoting DR is warranted.

- Curtailed loads would save $9-$26 million in energy ($85-$234 per megawatt-hour for the roughly 1,100 MW curtailed for 100 hours) and $73 million in capacity (at $58 per kW-yr of curtailable load), excluding equipment costs and the costs of administering a demand response program. These benefits would be recurring and would not be reduced by the offsetting effects discussed in Section 5.2, but they are calculated based on a rough proxy for the value of capacity, whereas the actual capacity price would vary over time and by location.

This study does not quantify several potentially large benefits of DR, including enhanced market competitiveness, reduced price volatility, insurance against extreme events, the option to curtail some load in the volatile real-time market, reduced capacity market prices affecting all load, and deferred T&D costs.

We also have not quantified offsetting effects that would likely reduce the quantified benefits to non-curtailed load energy market impacts in the long term. The long-term benefits of demand curtailment cannot be measured fully by this type of analysis. The long-term benefit will be determined by the extent to which adding DR to the resource mix lowers total resource costs.

Future research could include estimation of the additional benefits and offsets in the medium term, a long-term resource cost analysis, and an analysis of how customer participation and benefits depend on the design of demand response programs. MADRI and PJM could also build on the present study by incorporating learnings about program design from other market areas and simulating the market under various types of programs.

ABOUT THE AUTHORS

This report was prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI) by Samuel Newell and Frank Felder, with research assistance by Yuan Mei and with advice from Johannes Pfeifenberger and Ahmad Faruqui. Sam Newell is a Principal at *The Brattle Group,* where he focuses on energy market analysis, transmission project evaluation, generation asset valuation, and energy contracts. Frank A. Felder is the Director of the Center for Energy, Economic & Environmental Policy at Rutgers University and a Senior Advisor of *The Brattle Group*.

Appendix

Figure A-1. Impact of Load Curtailment on Prices at PJM Eastern Hub (AP Case)

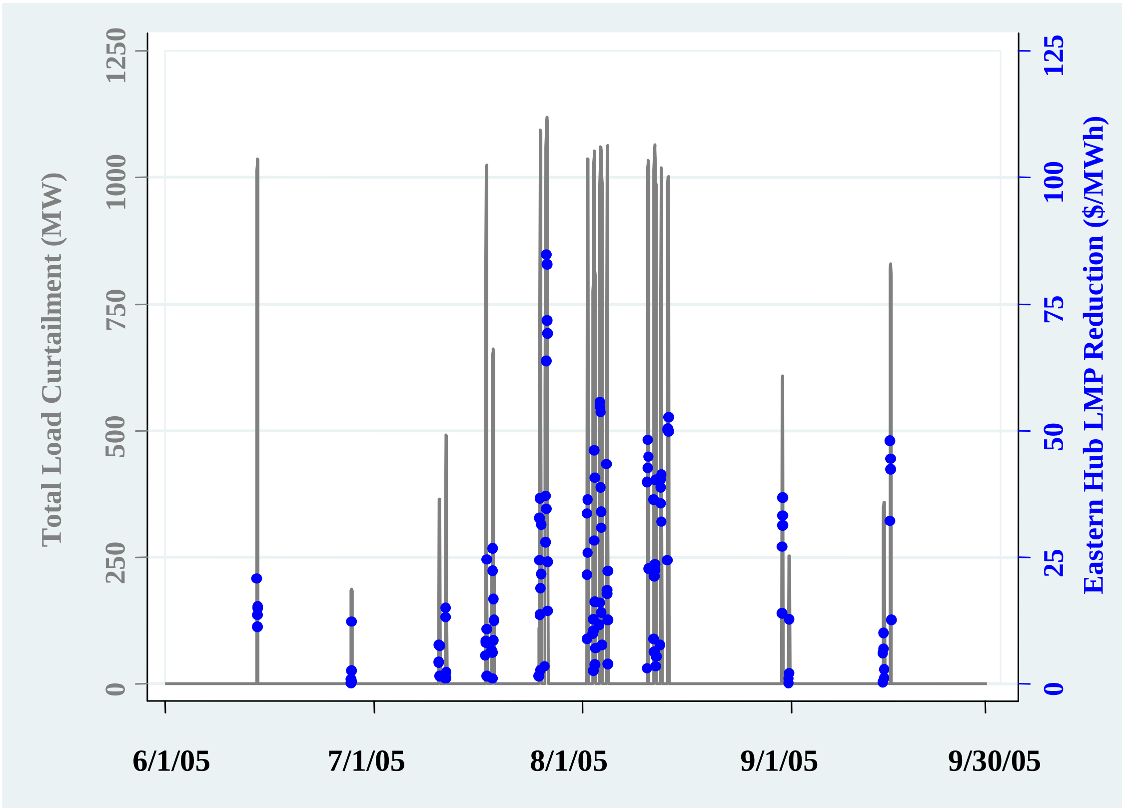

Figure A-2. Impact of Load Curtailment on Prices at PJM Eastern Hub (Normalized Case)

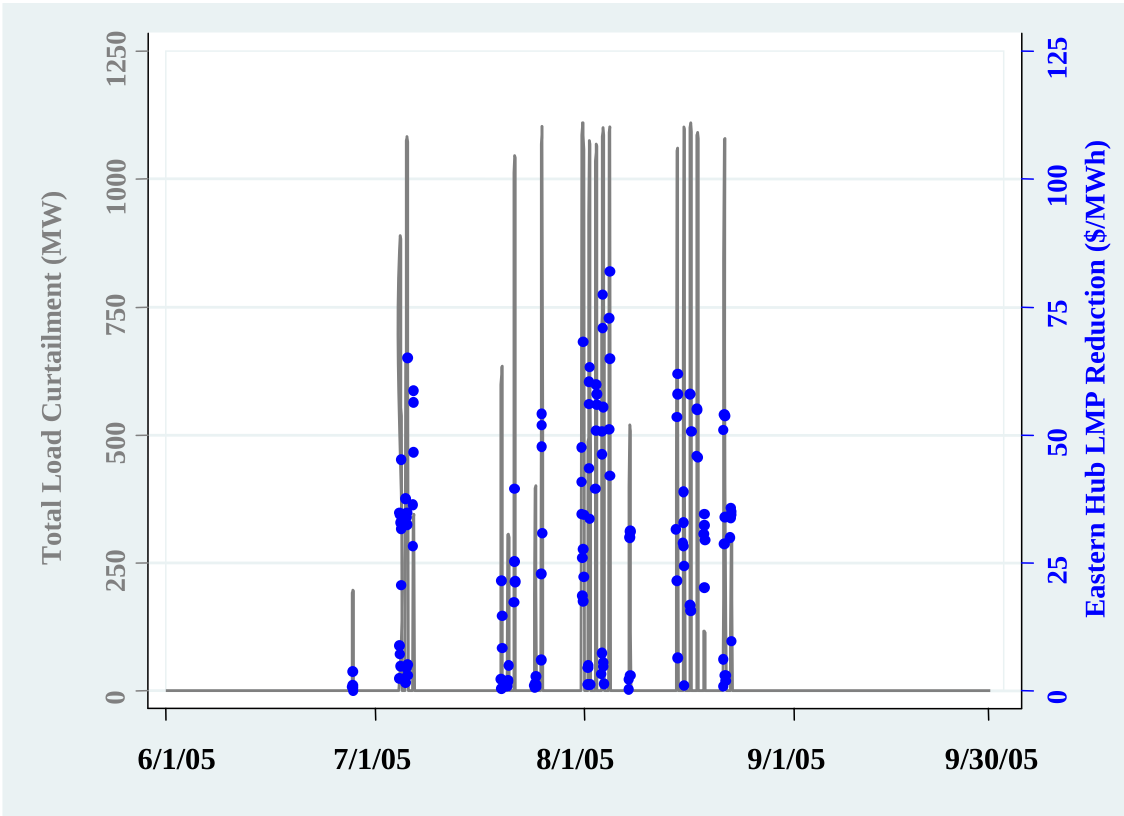

Figure A-3. Impact of Load Curtailment on Prices at PJM Eastern Hub (HP Case)

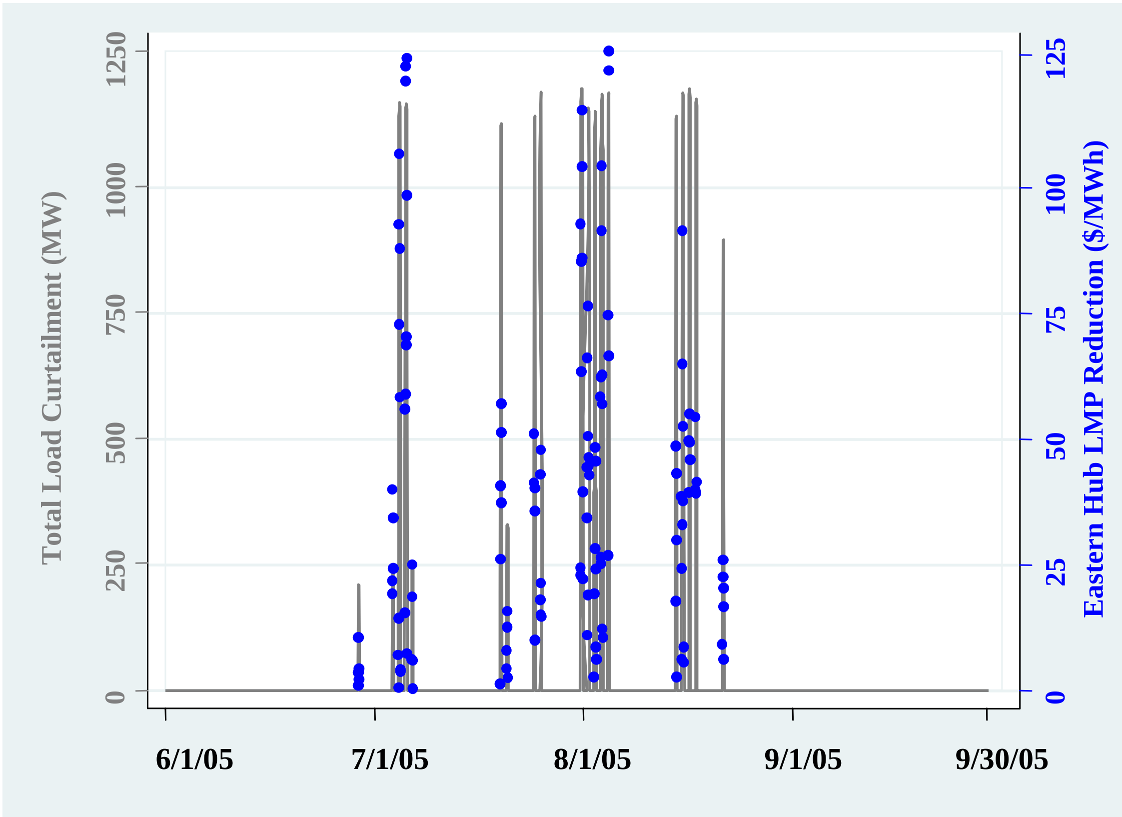

Figure A-4. Impact of Load Curtailment on Prices at PJM Eastern Hub (LP Case)

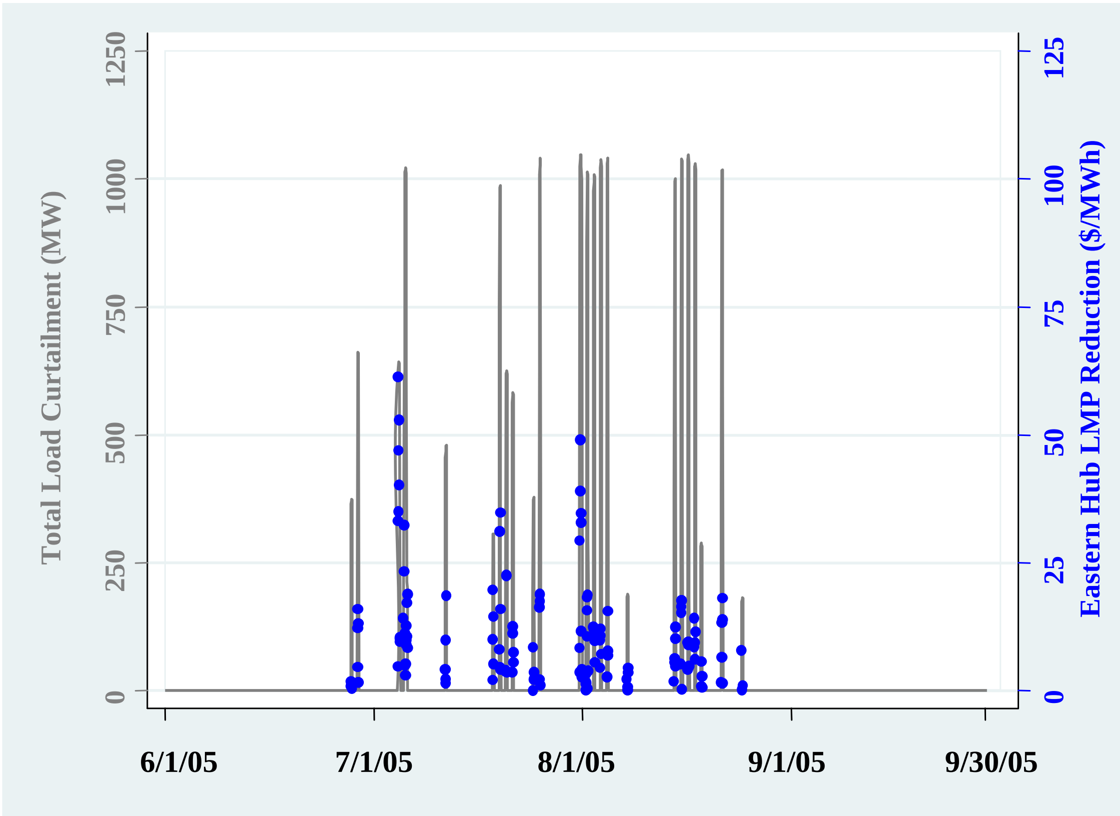

Figure A-5. Impact of Load Curtailment on Prices at PJM Eastern Hub (HF Case)

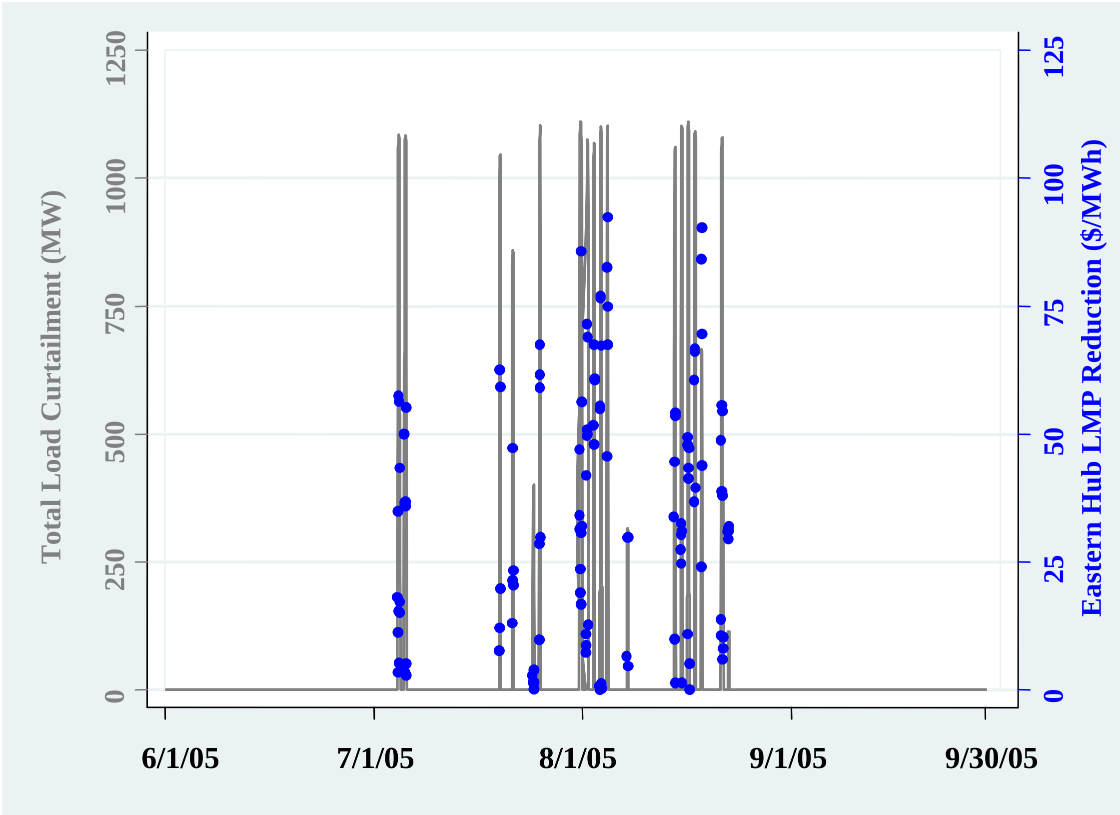

Figure A-6. Impact of Load Curtailment on Prices at PJM Eastern Hub (LF Case)

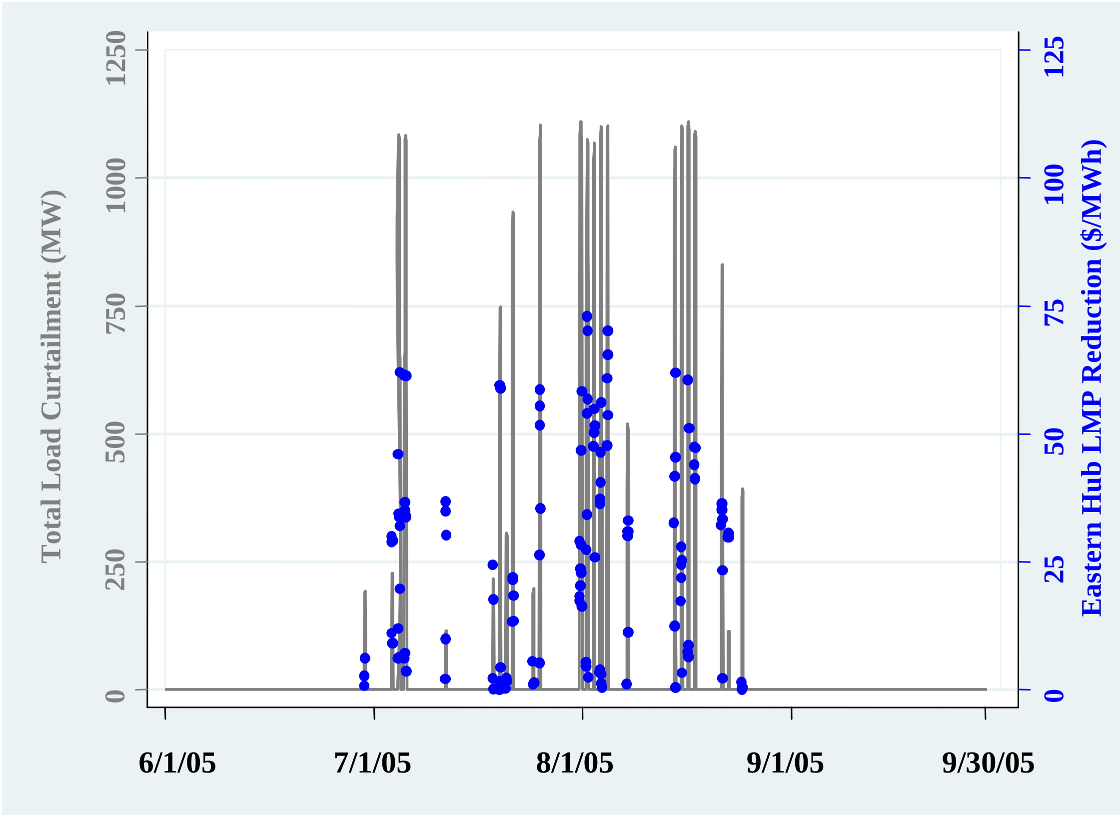

Table A-1. Price Impacts and Benefits to Non-Curtailed Loads, Actual Peak (AP) Case

Zone	MADRI	Curtailment Impacts During 137 Hours w/ At Least One Zone Curtailing							
		Weighted Average LMP Reduction		Average Load Curtailment		Average Residual	Gross Benefits	ARR Change	Net Benefits
		($/MWh) [A]	(%) [B]	(MW) [C]	(%) [D]	Load (MW) [E]	(Million $) [F]	(Million $) [G]	(Million $) [H]
BGE	**MD**	**$11**	**6%**	**142**	**2.2%**	**6,227**	**$9.5**	**($0.9)**	**$8.7**
DPL	**DE/MD****	**$21**	**10.6%**	**83**	**2.2%**	**3,623**	**$10.6**	**($2.4)**	**$8.3**
PECO	**PA**	**$15**	**7.8%**	**172**	**2.2%**	**7,531**	**$15.5**	**($2.8)**	**$12.7**
PEPCO	**DC/MD****	**$13**	**6.0%**	**135**	**2.2%**	**5,940**	**$10.2**	**($2.8)**	**$7.4**
PSEG	**NJ**	**$13**	**7.2%**	**211**	**2.2%**	**9,303**	**$17.1**	**($1.3)**	**$15.7**
AECO	**NJ**	**$10**	**4.7%**	**-**	**-**	**2,498**	**$3.3**	**$0.2**	**$3.5**
JCPL	**NJ**	**$12**	**6.8%**	**-**	**-**	**5,481**	**$9.3**	**($0.4)**	**$8.9**
DUQ	**PA**	**$2**	**1.6%**	**-**	**-**	**2,560**	**$0.7**	**($0.0)**	**$0.7**
METED	**PA**	**$13**	**6.6%**	**-**	**-**	**2,611**	**$4.6**	**($0.6)**	**$4.0**
PENELEC	**PA**	**$6**	**4.1%**	**-**	**-**	**2,626**	**$2.3**	**($0.3)**	**$2.0**
PPL	**PA**	**$12**	**6.6%**	**-**	**-**	**6,729**	**$10.9**	**($0.7)**	**$10.2**
APS	**PA/MD****	**$6**	**3.5%**	**-**	**-**	**8,094**	**$6.4**	**($4.3)**	**$2.0**
RECO	**NY**	**$10**	**5.9%**	**-**	**-**	**358**	**$0.5**	**$0.0**	**$0.5**
AEP	**-**	**$1**	**1.3%**	**-**	**-**	**20,867**	**$4.3**	**($0.9)**	**$3.3**
DAY	**-**	**$1**	**1.2%**	**-**	**-**	**3,064**	**$0.6**	**($0.0)**	**$0.6**
DOM	**-**	**$2**	**1.6%**	**-**	**-**	**16,741**	**$5.1**	**($1.2)**	**$3.9**
COMED	**-**	**$1**	**1.2%**	**-**	**-**	**16,806**	**$3.3**	**($0.0)**	**$3.3**
Total in Curtailed Zones		**$14**	**7.2%**	**743**	**2.2%**	**32,626**	**$62.9**	**($10.2)**	**$52.7**
Total in Non-Curtailed Zones		**$4**	**2.6%**	**0**	**0.0%**	**88,435**	**$51.3**	**($8.4)**	**$42.9**
Total by State	**PA**	**$11**	**5.8%**	**172**	**0.7%**	**25,514**	**$36.7**	**($6.3)**	**$30.4**
	NJ	**$13**	**6.7%**	**211**	**1.2%**	**17,282**	**$29.7**	**($1.6)**	**$28.1**
	DE	**$21**	**10.6%**	**57**	**2.2%**	**2,482**	**$7.3**	**($1.6)**	**$5.7**
	MD	**$12**	**6.0%**	**259**	**2.0%**	**12,886**	**$20.8**	**($4.3)**	**$16.5**
	DC	**$13**	**6.0%**	**41**	**2.2%**	**1,791**	**$3.1**	**($0.9)**	**$2.2**
MADRI Total		**$12**	**6.7%**	**740**	**1.2%**	**59,955**	**$97.5**	**($14.7)**	**$82.9**
Non-MADRI Total		**$2**	**3.1%**	**3**	**0.0%**	**61,106**	**$16.7**	**($3.9)**	**$12.8**
Total PJM		**$7**	**3.9%**	**743**	**0.6%**	**121,061**	**$114.2**	**($18.6)**	**$95.7**

Notes:
[A] and [B]: LMP reduction is weighted by hourly residual load.
[F] = [A] x [E] x number of hours with at least one zone curtailed.
[G]: 97% of ARRs are allocated to non-curtailed loads; the remainder is allocated to curtailed loads.
[H] = [F] + [G].
Benefits in zones spanning multiple states were allocated according to retail sales in June-September, 2005, from EIA form 826 reported in Global Energy Decisions Inc's *Energy Velocity*. Delmarva is allocated 28% to MD and 69% to DE (and 4% to VA). PEPCO is allocated 70% to MD and 30% to DC. APS, which has spillover price effects, is allocated 43% to PA and 19% to MD (and 29% to WV, 6% to VA, and 4% to OH).

Table A-2. Price Impacts and Benefits to Non-Curtailed Loads, Normalized (N) Case

Zone	MADRI	Curtailment Impacts During 147 Hours w/ At Least One Zone Curtailing							
		Weighted Average LMP Reduction		Average Load Curtailment		Average Residual	Gross Benefits	ARR Change	Net Benefits
		($/MWh) [A]	(%) [B]	(MW) [C]	(%) [D]	Load (MW) [E]	(Million $) [F]	(Million $) [G]	(Million $) [H]
BGE	MD	$13	6%	139	2.1%	6,585	$12.8	($0.6)	$12.1
DPL	DE/MD**	$27	11.9%	78	2.1%	3,702	$14.6	($4.0)	$10.6
PECO	PA	$16	7.4%	167	2.1%	7,906	$18.3	($3.4)	$14.9
PEPCO	DC/MD**	$17	7.1%	132	2.1%	6,223	$16.0	($4.4)	$11.6
PSEG	NJ	$14	6.8%	208	2.1%	9,759	$20.5	($1.1)	$19.4
AECO	NJ	$12	4.8%	-	-	2,564	$4.3	$0.1	$4.5
JCPL	NJ	$13	6.5%	-	-	5,631	$11.1	($0.6)	$10.4
DUQ	PA	$1	0.5%	-	-	2,761	$0.3	($0.0)	$0.3
METED	PA	$14	5.9%	-	-	2,602	$5.2	($0.7)	$4.5
PENELEC	PA	$7	3.4%	-	-	2,660	$2.6	($0.4)	$2.1
PPL	PA	$13	5.9%	-	-	6,961	$12.8	($1.2)	$11.6
APS	PA/MD**	$6	3.1%	-	-	8,303	$7.4	($7.0)	$0.4
RECO	NY	$10	5.4%	-	-	401	$0.6	$0.0	$0.7
AEP	-	$1	0.5%	-	-	21,250	$2.3	($0.8)	$1.5
DAY	-	$1	0.5%	-	-	3,010	$0.3	($0.0)	$0.3
DOM	-	$2	1.5%	-	-	17,033	$6.2	($1.7)	$4.5
COMED	-	$1	0.7%	-	-	18,168	$2.5	($0.0)	$2.5
Total in Curtailed Zones		$16	7.4%	724	2.1%	34,176	$82.1	($13.5)	$68.5
Total in Non-Curtailed Zones		$4	2.1%	0	0.0%	91,343	$55.7	($12.4)	$43.3
Total by State	PA	$11	5.2%	167	0.6%	26,435	$42.4	($8.8)	$33.6
	NJ	$14	6.4%	208	1.1%	17,954	$35.9	($1.6)	$34.3
	DE	$27	11.9%	53	2.1%	2,537	$10.0	($2.7)	$7.2
	MD	$15	6.4%	252	1.8%	13,501	$29.3	($6.1)	$23.2
	DC	$17	7.1%	40	2.1%	1,877	$4.8	($1.3)	$3.5
MADRI Total		$13	7.1%	721	1.1%	62,304	$122.4	($20.5)	$101.9
Non-MADRI Total		$2	2.6%	3	0.0%	63,216	$15.4	($5.4)	$9.9
Total PJM		$7	3.6%	724	0.6%	125,519	$137.8	($26.0)	$111.8

Notes:
[A] and [B]: LMP reduction is weighted by hourly residual load.
[F] = [A] x [E] x number of hours with at least one zone curtailed.
[G]: 97% of ARRs are allocated to non-curtailed loads; the remainder is allocated to curtailed loads.
[H] = [F] + [G].
Benefits in zones spanning multiple states were allocated according to retail sales in June-September, 2005, from EIA form 826 reported in Global Energy Decisions Inc's *Energy Velocity*. Delmarva is allocated 28% to MD and 69% to DE (and 4% to VA). PEPCO is allocated 70% to MD and 30% to DC. APS, which has spillover price effects, is allocated 43% to PA and 19% to MD (and 29% to WV, 6% to VA, and 4% to OH).

Table A-3. Price Impacts and Benefits to Non-Curtailed Loads, High Peak (HP) Case

Zone	MADRI	Curtailment Impacts During 133 Hours w/ At Least One Zone Curtailing							
		Weighted Average LMP Reduction		Average Load Curtailment		Average Residual	Gross Benefits	ARR Change	Net Benefits
		($/MWh) [A]	(%) [B]	(MW) [C]	(%) [D]	Load (MW) [E]	(Million $) [F]	(Million $) [G]	(Million $) [H]
BGE	MD	$24	8%	162	2.3%	6,960	$22.5	($2.3)	$20.2
DPL	DE/MD**	$37	10.4%	91	2.3%	3,894	$19.2	($1.8)	$17.4
PECO	PA	$42	11.6%	195	2.3%	8,399	$46.4	($15.3)	$31.1
PEPCO	DC/MD**	$25	7.8%	154	2.3%	6,578	$22.3	($4.6)	$17.7
PSEG	NJ	$26	8.2%	244	2.3%	10,401	$36.3	($1.1)	$35.2
AECO	NJ	$31	8.0%	-	-	2,716	$11.0	($0.3)	$10.8
JCPL	NJ	$24	7.7%	-	-	6,035	$19.5	($1.0)	$18.5
DUQ	PA	$2	0.9%	-	-	2,972	$0.8	($0.1)	$0.8
METED	PA	$22	6.4%	-	-	2,765	$8.0	($1.0)	$7.0
PENELEC	PA	$17	4.7%	-	-	2,840	$6.2	($1.3)	$5.0
PPL	PA	$19	6.3%	-	-	7,406	$18.7	($1.6)	$17.1
APS	PA/MD**	$9	3.1%	-	-	8,843	$10.3	($6.3)	$4.0
RECO	NY	$18	6.2%	-	-	429	$1.0	$0.1	$1.2
AEP	-	$2	1.0%	-	-	22,718	$7.0	($4.9)	$2.1
DAY	-	$0	0.0%	-	-	3,231	$0.0	($0.1)	($0.1)
DOM	-	$6	2.4%	-	-	18,028	$13.9	($1.6)	$12.3
COMED	-	$1	0.6%	-	-	19,877	$2.7	($0.1)	$2.7
Total in Curtailed Zones		$30	9.1%	845	2.3%	36,231	$146.6	($25.0)	$121.6
Total in Non-Curtailed Zones		$8	2.6%	0	0.0%	97,861	$99.2	($18.0)	$81.2
Total by State	PA	$23	6.7%	195	0.7%	28,158	$84.5	($21.9)	$62.6
	NJ	$26	8.0%	244	1.3%	19,152	$66.8	($2.4)	$64.5
	DE	$37	10.4%	62	2.3%	2,668	$13.1	($1.2)	$11.9
	MD	$24	7.4%	295	2.0%	14,277	$45.3	($7.2)	$38.1
	DC	$25	7.8%	46	2.3%	1,984	$6.7	($1.4)	$5.3
MADRI Total		$25	7.9%	842	1.3%	66,238	$216.5	($34.0)	$182.4
Non-MADRI Total		$3	3.4%	3	0.0%	67,854	$29.4	($9.0)	$20.3
Total PJM		$14	4.3%	845	0.6%	134,092	$245.8	($43.1)	$202.8

Notes:
[A] and [B]: LMP reduction is weighted by hourly residual load.
[F] = [A] x [E] x number of hours with at least one zone curtailed.
[G]: 97% of ARRs are allocated to non-curtailed loads; the remainder is allocated to curtailed loads.
[H] = [F] + [G].
Benefits in zones spanning multiple states were allocated according to retail sales in June-September, 2005, from EIA form 826 reported in Global Energy Decisions Inc's *Energy Velocity*. Delmarva is allocated 28% to MD and 69% to DE (and 4% to VA). PEPCO is allocated 70% to MD and 30% to DC. APS, which has spillover price effects, is allocated 43% to PA and 19% to MD (and 29% to WV, 6% to VA, and 4% to OH).

Table A-4. Price Impacts and Benefits to Non-Curtailed Loads, Low Peak (LP) Case

Zone	MADRI	Curtailment Impacts During 152 Hours w/ At Least One Zone Curtailing							
		Weighted Average LMP Reduction		Average Load Curtailment		Average Residual	Gross Benefits	ARR Change	Net Benefits
		($/MWh) [A]	(%) [B]	(MW) [C]	(%) [D]	Load (MW) [E]	(Million $) [F]	(Million $) [G]	(Million $) [H]
BGE	MD	$8	5%	126	2.0%	6,184	$7.8	($1.1)	$6.7
DPL	DE/MD**	$10	5.8%	71	2.0%	3,466	$5.1	($0.3)	$4.8
PECO	PA	$11	6.4%	152	2.0%	7,434	$12.6	($3.8)	$8.8
PEPCO	DC/MD**	$9	5.0%	120	2.0%	5,869	$7.9	($2.4)	$5.4
PSEG	NJ	$10	5.8%	191	2.0%	9,200	$13.6	($1.2)	$12.3
AECO	NJ	$7	3.7%	-	-	2,390	$2.6	$0.2	$2.8
JCPL	NJ	$8	5.2%	-	-	5,284	$6.6	($0.5)	$6.1
DUQ	PA	$0	0.3%	-	-	2,620	$0.2	$0.0	$0.2
METED	PA	$8	4.9%	-	-	2,449	$3.1	($0.5)	$2.5
PENELEC	PA	$4	2.8%	-	-	2,517	$1.7	($0.4)	$1.3
PPL	PA	$7	4.6%	-	-	6,566	$7.1	($0.7)	$6.4
APS	PA/MD**	$5	3.1%	-	-	7,848	$5.9	($5.7)	$0.2
RECO	NY	$6	3.8%	-	-	378	$0.3	$0.0	$0.4
AEP	-	$0	0.5%	-	-	20,100	$1.5	($0.8)	$0.7
DAY	-	$0	0.4%	-	-	2,864	$0.2	$0.0	$0.2
DOM	-	$2	1.8%	-	-	15,993	$5.8	($1.4)	$4.3
COMED	-	$1	0.5%	-	-	17,337	$1.5	($0.0)	$1.5
Total in Curtailed Zones		$10	5.6%	660	2.0%	32,152	$47.0	($8.9)	$38.1
Total in Non-Curtailed Zones		$3	1.9%	0	0.0%	86,347	$36.5	($9.9)	$26.6
Total by State	PA	$7	4.3%	152	0.6%	24,936	$27.2	($7.9)	$19.3
	NJ	$9	5.3%	191	1.1%	16,874	$22.8	($1.6)	$21.2
	DE	$10	5.8%	48	2.0%	2,375	$3.5	($0.2)	$3.3
	MD	$8	4.8%	230	1.8%	12,703	$15.8	($4.0)	$11.9
	DC	$9	5.0%	36	2.0%	1,770	$2.4	($0.7)	$1.6
MADRI Total		$8	5.0%	657	1.1%	58,657	$71.7	($14.4)	$57.3
Non-MADRI Total		$1	2.3%	3	0.0%	59,842	$11.8	($4.4)	$7.4
Total PJM		$5	2.9%	660	0.6%	118,500	$83.5	($18.8)	$64.7

Notes:
[A] and [B]: LMP reduction is weighted by hourly residual load.
[F] = [A] x [E] x number of hours with at least one zone curtailed.
[G]: 97% of ARRs are allocated to non-curtailed loads; the remainder is allocated to curtailed loads.
[H] = [F] + [G].
Benefits in zones spanning multiple states were allocated according to retail sales in June-September, 2005, from EIA form 826 reported in Global Energy Decisions Inc's *Energy Velocity*. Delmarva is allocated 28% to MD and 69% to DE (and 4% to VA). PEPCO is allocated 70% to MD and 30% to DC. APS, which has spillover price effects, is allocated 43% to PA and 19% to MD (and 29% to WV, 6% to VA, and 4% to OH).

Table A-5. Price Impacts and Benefits to Non-Curtailed Loads, High Fuel (HF) Case

Zone	MADRI	Curtailment Impacts During 135 Hours w/ At Least One Zone Curtailing							
		Weighted Average LMP Reduction		Average Load Curtailment		Average Residual	Gross Benefits	ARR Change	Net Benefits
		($/MWh) [A]	(%) [B]	(MW) [C]	(%) [D]	Load (MW) [E]	(Million $) [F]	(Million $) [G]	(Million $) [H]
BGE	MD	$17	7%	151	2.2%	6,583	$15.5	($0.7)	$14.7
DPL	DE/MD**	$32	12.0%	85	2.2%	3,696	$16.2	($3.8)	$12.4
PECO	PA	$21	8.4%	182	2.2%	7,927	$22.8	($3.7)	$19.1
PEPCO	DC/MD**	$21	7.5%	143	2.2%	6,225	$18.0	($4.5)	$13.5
PSEG	NJ	$19	7.7%	227	2.3%	9,819	$25.8	($1.1)	$24.7
AECO	NJ	$16	5.6%	-	-	2,561	$5.7	$0.2	$5.8
JCPL	NJ	$19	7.5%	-	-	5,661	$14.3	($0.7)	$13.6
DUQ	PA	$1	0.9%	-	-	2,777	$0.5	$0.0	$0.5
METED	PA	$19	7.0%	-	-	2,619	$6.7	($0.9)	$5.8
PENELEC	PA	$10	4.1%	-	-	2,682	$3.5	($0.6)	$2.9
PPL	PA	$18	7.1%	-	-	7,008	$16.8	($1.2)	$15.7
APS	PA/MD**	$7	2.9%	-	-	8,332	$7.4	($6.0)	$1.4
RECO	NY	$15	6.7%	-	-	404	$0.8	$0.1	$0.9
AEP	-	$1	0.8%	-	-	21,280	$3.4	($0.9)	$2.5
DAY	-	$1	0.8%	-	-	3,005	$0.5	($0.0)	$0.5
DOM	-	$3	1.6%	-	-	17,051	$7.4	($1.7)	$5.6
COMED	-	$2	1.0%	-	-	18,084	$3.7	($0.0)	$3.6
Total in Curtailed Zones		$21	8.0%	788	2.2%	34,249	$98.2	($13.8)	$84.4
Total in Non-Curtailed Zones		$6	2.5%	0	0.0%	91,466	$70.7	($11.9)	$58.8
Total by State	PA	$15	6.0%	182	0.7%	26,571	$53.6	($9.0)	$44.6
	NJ	$19	7.3%	227	1.2%	18,040	$45.7	($1.6)	$44.0
	DE	$32	12.0%	58	2.2%	2,533	$11.1	($2.6)	$8.5
	MD	$19	6.8%	274	2.0%	13,504	$33.9	($6.0)	$27.9
	DC	$21	7.5%	43	2.2%	1,877	$5.4	($1.3)	$4.1
MADRI Total		$18	7.6%	785	1.2%	62,524	$149.6	($20.6)	$129.1
Non-MADRI Total		$2	3.0%	3	0.0%	63,191	$19.2	($5.1)	$14.1
Total PJM		$10	4.0%	788	0.6%	125,715	$168.9	($25.7)	$143.2

Notes:
[A] and [B]: LMP reduction is weighted by hourly residual load.
[F] = [A] x [E] x number of hours with at least one zone curtailed.
[G]: 97% of ARRs are allocated to non-curtailed loads; the remainder is allocated to curtailed loads.
[H] = [F] + [G].
Benefits in zones spanning multiple states were allocated according to retail sales in June-September, 2005, from EIA form 826 reported in Global Energy Decisions Inc's *Energy Velocity*. Delmarva is allocated 28% to MD and 69% to DE (and 4% to VA). PEPCO is allocated 70% to MD and 30% to DC. APS, which has spillover price effects, is allocated 43% to PA and 19% to MD (and 29% to WV, 6% to VA, and 4% to OH).

Table A-6. Price Impacts and Benefits to Non-Curtailed Loads, Low Fuel (LF) Case

Zone	MADRI	Curtailment Impacts During 152 Hours w/ At Least One Zone Curtailing							
		Weighted Average LMP Reduction		Average Load Curtailment		Average Residual	Gross Benefits	ARR Change	Net Benefits
		($/MWh) [A]	(%) [B]	(MW) [C]	(%) [D]	Load (MW) [E]	(Million $) [F]	(Million $) [G]	(Million $) [H]
BGE	MD	$12	6%	134	2.0%	6,552	$11.5	($0.8)	$10.6
DPL	DE/MD**	$23	12.4%	75	2.0%	3,678	$13.1	($3.6)	$9.4
PECO	PA	$14	8.0%	160	2.0%	7,859	$17.0	($4.1)	$13.0
PEPCO	DC/MD**	$15	7.2%	127	2.0%	6,214	$14.3	($3.9)	$10.4
PSEG	NJ	$13	7.2%	201	2.0%	9,724	$18.9	($1.3)	$17.6
AECO	NJ	$11	5.2%	-	-	2,531	$4.1	$0.0	$4.1
JCPL	NJ	$12	6.8%	-	-	5,580	$9.9	($0.6)	$9.4
DUQ	PA	$1	0.7%	-	-	2,752	$0.3	($0.0)	$0.3
METED	PA	$11	5.9%	-	-	2,593	$4.4	($0.6)	$3.8
PENELEC	PA	$5	2.9%	-	-	2,662	$1.9	($0.3)	$1.6
PPL	PA	$10	5.7%	-	-	6,944	$10.3	($0.8)	$9.5
APS	PA/MD**	$4	2.6%	-	-	8,309	$5.4	($4.9)	$0.5
RECO	NY	$8	5.3%	-	-	399	$0.5	$0.1	$0.6
AEP	-	$1	0.5%	-	-	21,352	$1.8	($0.8)	$1.1
DAY	-	$1	0.5%	-	-	3,041	$0.2	($0.0)	$0.2
DOM	-	$2	1.5%	-	-	17,014	$5.1	($1.3)	$3.9
COMED	-	$1	0.7%	-	-	18,475	$2.0	($0.0)	$2.0
Total in Curtailed Zones		$14	7.8%	699	2.0%	34,028	$74.8	($13.8)	$61.0
Total in Non-Curtailed Zones		$3	2.1%	0	0.0%	91,649	$46.1	($9.2)	$36.9
Total by State	PA	$9	5.2%	160	0.6%	26,357	$36.3	($7.9)	$28.4
	NJ	$12	6.8%	201	1.1%	17,835	$33.0	($1.9)	$31.1
	DE	$23	12.4%	52	2.0%	2,520	$9.0	($2.5)	$6.5
	MD	$13	6.6%	244	1.8%	13,456	$26.1	($5.5)	$20.6
	DC	$15	7.2%	38	2.0%	1,874	$4.3	($1.2)	$3.1
MADRI Total		$12	7.3%	696	1.1%	62,042	$108.6	($19.0)	$89.6
Non-MADRI Total		$1	2.6%	3	0.0%	63,635	$12.3	($4.1)	$8.3
Total PJM		$6	3.6%	699	0.6%	125,677	$120.9	($23.0)	$97.9

Notes:
[A] and [B]: LMP reduction is weighted by hourly residual load.
[F] = [A] x [E] x number of hours with at least one zone curtailed.
[G]: 97% of ARRs are allocated to non-curtailed loads; the remainder is allocated to curtailed loads.
[H] = [F] + [G].
Benefits in zones spanning multiple states were allocated according to retail sales in June-September, 2005, from EIA form 826 reported in Global Energy Decisions Inc's *Energy Velocity*. Delmarva is allocated 28% to MD and 69% to DE (and 4% to VA). PEPCO is allocated 70% to MD and 30% to DC. APS, which has spillover price effects, is allocated 43% to PA and 19% to MD (and 29% to WV, 6% to VA, and 4% to OH).

Appendix 8.1c

Ontario Energy Board

Ontario Energy Board Smart Price Pilot Final Report

July 2007

Prepared by IBM Global Business Services and eMeter Strategic Consulting for the Ontario Energy Board

Strategic Consulting

IBM

Contents

List of Exhibits

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Finally, Chris Cincar of the OEB was more than a typical client project manager. We are indebted to him for his overall guidance and detailed reviews. The overall quality of the study and final report is much enhanced through his involvement.

James Strapp, IBM
Chris King, eMeter
Sharon Talbott, eMeter
July 2007

Executive Summary

In June 2006, the Ontario Energy Board (the Board) initiated the Ontario Energy Board Smart Price Pilot (OSPP) project to test the reactions and impacts on consumer behaviour of different time-sensitive price structures. By August 1, 2006, 375 of Hydro Ottawa's electricity customers had been placed into one of three pricing groups and were receiving monthly Electricity Usage Statements in addition to their bi-monthly electricity bills.

The OSPP was operated until February 28, 2007 with the intent to assess:

- The extent to which various time-sensitive pricing structures cause a shift of electricity consumption to off-peak periods as measured by the reduction in peak demand
- The extent to which each price structure causes a change in total monthly consumption.
- The understandability of and acceptability by residential consumers of each pricing structure and the communications associated with each.

Results of the OSPP were measured through the quantitative analysis of demand response, total energy conservation, and participant survey responses. Qualitative feedback was garnered from focus groups and tracking of participant support calls.

The results are intended to inform the Board with respect to future decisions associated with time-sensitive prices including the potential application of critical peak pricing and any refinements to the current Regulated Price Plan (RPP) time-of-use (TOU) pricing structure and associated consumer communications. [1]

Price Designs

The OSPP tested three different price structures:

- The existing RPP TOU prices, as in the table below.
- Adjusted RPP TOU prices with a critical peak price (CPP)
- RPP TOU prices with a critical peak rebate (CPR)

[1] - The RPP is primarily for low volume electricity consumers that do not opt to switch to a retailer. The Board sets two-tier and TOU commodity prices as part of the RPP. Virtually all RPP consumers in Ontario currently pay two-tiered threshold (non-TOU) prices.

Time	Summer Hours (Aug 1 - Oct 31)	Price/ kWh	Winter Hours (Nov 1 - Feb 28)	Price/ kWh
Off-Peak	10 pm - 7 am weekdays; all day on weekends and holidays	3.5¢	10 pm - 7 am weekdays; all day on weekends and holidays	3.4¢
Mid-Peak	7 am - 11 am and 5 pm - 10 pm weekdays	7.5¢	11 am - 5 pm and 8 pm - 10 pm weekdays	7.1¢
On-Peak	11 am - 5 pm weekdays	10.5¢	7 am - 11 am and 5 pm - 8pm weekdays	9.7¢

TOU prices are unchanged from the Board's existing Regulated Price Plan (RPP) TOU prices

Critical peak pricing is the application of different prices for specific hours of the year when the electricity system is stressed and/or hourly energy market prices are high. For the OSPP, critical peaks were to occur only for 3 or 4 hours during the On-Peak period, and only on declared critical peak days. Critical peak days were declared based on temperature and Humidex thresholds. Participants were notified by telephone, email or text messages one day before the event.

The maximum number of critical peak days planned for the pilot was nine. During the pilot, seven critical peak events were declared due to moderate weather: two in August, two in September and three in January.

A critical peak price of 30¢ per kWh was set based on the average of the 93 highest hourly Ontario electricity prices in the previous year. For critical peak price (CPP) participants, the RPP Off-Peak price was reduced to 3.1 ¢/kWh to offset the increase in the critical peak price.

In contrast to CPP, participants on the critical peak rebate plan were provided a refund of 30¢ for every kWh reduction below their "baseline" usage during the critical peak hours. The baseline was calculated as the average usage for the same hours of the five previous non-event, non-holiday weekdays, multiplied by 125% as a weather adjustment.

All prices are related to the commodity portion of a customer's electricity bill; delivery, debt retirement, and other charges were not changed as a result of the pilot.

Customer Participation

Candidate participants were randomly selected from the population that would have smart meters installed in Hydro Ottawa's territory by August 1, 2006.

In a marked difference from other residential TOU pilot projects, the OSPP was over-subscribed after only one recruitment solicitation and within about one week. While a 10% enrolment rate was expected, in fact, out of 1,800 recruitment letters sent (600 for each targeted price group) to customers with smart meters, 459 people responded by submitting an enrolment form before enrolment was closed, a 25.5% response rate.

The result was 373 participants in the pilot, 125 in a CPR price group, and 124 each in TOU-only and CPP groups.

The control group is a sample of 125 customers selected randomly from the population of Hydro Ottawa residential customers who had smart meters installed prior to the August 1, 2006 start of the pilot but continued to pay regular tiered (non-TOU) prices.

All treatment and control participants are RPP consumers (i.e., not on a retailer contract).

Pilot Operation

Upon enrolment, participants were provided with a table of the TOU prices, periods, and seasons for the participant's price plan on a refrigerator magnet, and a PowerWise electricity conservation brochure.

As an incentive to enrol, participants received a "thank you payment" of $75.00 at the end of the pilot, adjusted as described below.

To accommodate the needs of the pilot, participants continued to receive and pay their "normal" bi-monthly electricity bill from Hydro Ottawa.

Separately, pilot participants received monthly Electricity Usage Statements that showed their electricity supply charges on their respective pilot price plan. The statements were mailed to participants monthly, and all usage was on a calendar month basis.

At the end of the pilot, participants received a final settlement statement comparing their electricity charges on the pilot prices with what their charges would have been on the two-tiered RPP prices.

With a final settlement in March 2007, at the end of the pilot, participants received a cheque in an amount equal to the base $75 incentive adjusted by the amount of their savings or losses on TOU pricing. Thus, participants faced actual economic gains or losses based on their response, or lack thereof, to TOU prices.

Demand Response Results

The analysis of demand response or peak shifting as a result of the pilot prices was performed by Professor Frank Wolak of the Economics Department of Stanford University.

The analysis was performed to assess the following:

- Demand response via load shifting away from critical peak hours to either Mid-Peak or Off-Peak hours on critical peak days
- Demand response via load shifting away from On-Peak hours to either Mid-Peak or Off-Peak hours on all non-holiday weekdays

These effects are determined by comparing the electricity consumption behaviour of customers receiving the experimental prices (TOU, CPP, and CPR) and the behaviour of customers remaining on their existing two-tier RPP prices. These customer groups are the treatment and control groups respectively.

Critical Peak Days

The table below shows the amount of load shifting on individual critical peak days for all three price groups combined for the entire On-Peak period. A statistically significant shift in load away from peak periods was measured during On-Peak periods on two critical peak days called in August. No statistically significant shift was detected during the critical peak days declared in September or January, except for a counterintuitive result for January 17.

Critical Peak Day (Entire Peak Period)	Summertime Load Shifting	Actual Max Temp (°C)	Actual Max Humidex
Friday, August 18	27.7%	30.0	35
Tuesday, August 29	10.1%	25.2	28
Thursday, September 7	n/s	22.4	n/a
Friday, September 8	n/s	26.5	31
	Wintertime Load Shifting	**Actual Min Temp (°C) During Peak Period**	
Tuesday, January 16	n/s	-18.7	
Wednesday, January 17	-7.2%	-16.1	
Friday, January 26	n/s	-21.3	

Statistically significant load shifting was detected for the first two summertime and the second wintertime critical peak events – though the winter result is counterintuitive. Seven critical peak events (against a target of nine) were called during the pilot using forecast temperature thresholds of 28°C in summer (or a Humidex above 30°C) and -14°C in winter. Results are statistically significant at the 90% level, unless denoted by "n/s".

Results that are not statistically significant at the 90% level are denoted by "n/s"; however, many of the load shift results are statistically significant at the 95% and even 99% confidence level.

As detailed in the table on the following page, the resulting load shifting during critical peak hours across all four summertime critical peak days ranged from 5.7% for TOU-only participants to 25.4% CPP participants. Percentage load shifting during the entire summertime peak period (11am to 5pm) during the same critical peak days was less, ranging from 2.4% to 11.9%.

Summertime Period	TOU only	CPP	CPR
Critical peak hours (3 or 4 hours during the peak)	5.7%(n/s)[2]	25.4%	17.5%
Entire On-Peak period (6 hours)	2.4%(n/s)[2]	11.9%	8.5%

Percentage shift in load during the four summertime critical peak days of the pilot.

All Days

Load shifting away from the On-Peak period for all days in the pilot, not just critical peak days, was also analyzed. These results showed no applicable statistically significant load shifting from On-Peak periods as a result of the TOU price structure alone.

Conservation Effects

The analysis compared the usage of the treatment and control groups before the pilot, then after going on the pilot.

These results show a 6.0% average conservation effect across all customers. All of the results are statistically significant.

Price Group	Percent reduction in total electricity use
TOU	6.0%
CPP	4.7%(n/s)[3]
CPR	7.4%
Average	**6.0%**

Conservation Effect (total usage reduction) for the full pilot period

Customer Bill Impacts

Total Load Shift Impacts

The impacts on bills were determined by calculating each individual participant's bills during the pilot under the TOU prices versus the two-tiered RPP prices. Thus, any

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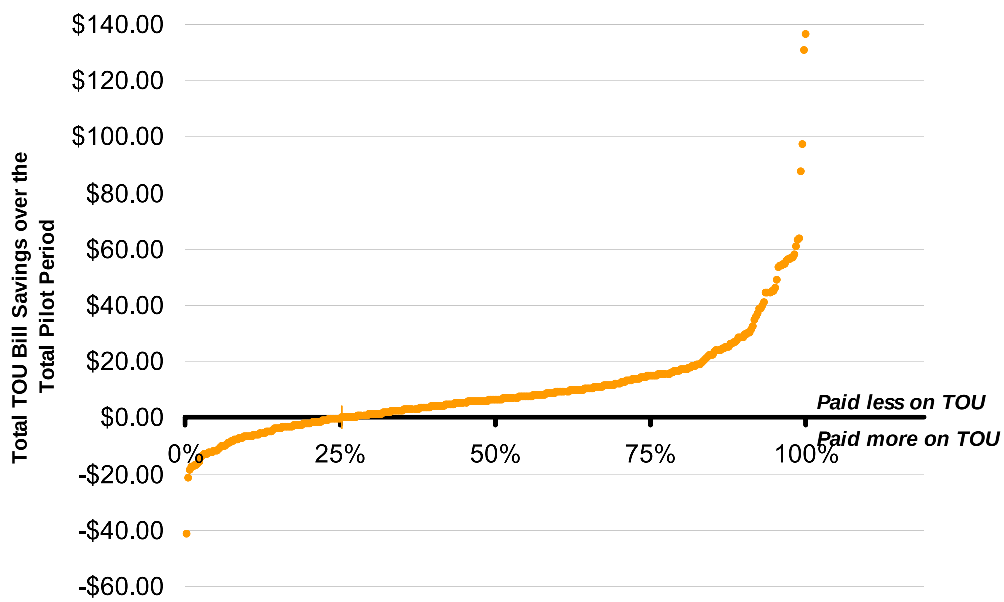
[2] The percentage reductions for the TOU-only customers are not statistically significant at a 90% confidence level and can therefore not be as readily generalized to a large population. They do represent actual reductions recorded for that group. Had there been more critical peak days, it is likely these results would be statistically significant.

[3] - This result is not statistically significant at the 90% confidence level but is included here because it is significant at a confidence level of 88%, or just less than 90%. This small difference does not apply to the other "n/s" results in this report.

bill savings is entirely a result of load shifting. Conservation effects which lower a participant's usage compared to what it would have been without TOU prices are not considered in these results.[4]

Over the course of the entire pilot period, on average, participants shifted load and paid 3.0% lower bills on the TOU pilot prices than they would have on regular tiered RPP price. Savings were spread across participants with three quarters of participants paying less on the TOU prices.

Since only seven critical peak days were declared against a target of nine, CPP participants realized savings that were somewhat overstated. Conversely, CPR participants realized lower rebates during the pilot for the same reason.



Distribution of participant bills savings on TOU prices for the total pilot period as a result of load shifting alone (i.e. not conservation). Each dot represents an individual participant's net loss or savings. Those above the line paid less on TOU prices.

Monthly Load Shift Impacts

Monthly comparisons between TOU and the two-tiered RPP threshold prices are problematic. The RPP threshold prices are designed from a year-long perspective, taking into consideration expected higher usage in summer and winter months, and

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[4] - While it was the TOU price plans that triggered the "conservation effect", the reduction in consumption would be reflected in charges on both two-tier prices and TOU prices.

lower usage in spring and fall months. The RPP seasonal tier threshold changes from 600 kWh to 1,000 kWh per month in November. Under this price structure, consumers who use more than the threshold level of usage pay a higher average price in the summer than the winter. Over the full pilot, such threshold effects are offset when looking at the total bill impacts.

Monthly comparisons are provided in this report to understand the implications for participant's making individual bill comparisons. Results by individual month were generally consistent with the total.

August was the only month that the average savings across all three price groups was below zero. It was in August that the most participants experienced a significant increase, with one participant experiencing monthly increases as high as $12.81. Savings of up to $35.55 in an individual month were experienced by some participants.

These cost increases or savings were extreme. Of the approximately 2625 statements issued, 5% had TOU savings greater than $8.84. Similarly, only 5% had costs greater than $3.46.

Savings from Conservation Impacts

Savings when the conservation effect is considered would be greater. Assuming a 6.0% conservation effect alone, and based on the average price of 5.9¢/kWh, the savings would range from a few cents for the lowest volume user to over $6 per month for the largest user. Average monthly use for pilot participants was 727 kWh after conserving 6%, ranging from 683 kWh for the TOU-only group to 774 kWh for the CPR group. Thus the conservation effect at the average price of 5.9¢/kWh resulted in savings averaging $2.73 per month.

With this conservation effect added to the load shifting impacts, the average monthly TOU bill savings from both load shifting and conservation effects was $4.17. With conservation considered, 93% of customers would pay less on RPP TOU prices over the course of the pilot, than they would have on RPP threshold prices (compared to 75% without conservation being considered).

Participant Feedback

Participant feedback was gained from two primary methods:

- Three focus groups with 44 participants were conducted in Ottawa during the second week of October; one group each for CPP, CPR, and TOU participants.
- A survey of the program participants was conducted. A total of 298 surveys were returned by the survey cut-off date of December 14, 2006, for an overall response rate of 79%. The margin of error (at 95% confidence) for the overall results is ± 5.7% for the 298 surveys received.

Overall satisfaction

The majority (78%) of survey respondents would recommend the time-of-use pricing plan to their friends, while only 6% would definitely not. These results are consistent regardless of which pricing plan the participants were enrolled in for the pilot.

Respondents most frequently cited more awareness of how to reduce their bill, giving greater control over their electricity costs and environmental benefits as the top three reasons behind the satisfaction.

Those not sure or who would not recommend the program cited insufficient potential savings and too much effort as the reasons why.

Pricing preferences

Regardless of the pricing plan in which they were enrolled, the majority of participants (74%) preferred TOU-only pricing out of the four options.

While interest in the CPP and CPR plans was only moderate, less than 20% prefer the existing two-tier threshold pricing used by Hydro Ottawa before the pilot. Most would not want to go back to two-tier pricing.

Expected Bill Impact

The impact on individual bills seemed to be less than many focus group participants had hoped. Few of the focus group participants felt they had realized "large" savings on their electricity bills. In fact, many focus group participants expressed disappointment that their efforts did not result in greater savings.

These bill comparisons by participants are complicated by many factors:

- Comparisons of pilot Electricity Usage Statements calculated for each calendar month against bi-monthly bills from Hydro Ottawa calculated from various billing dates
- Comparisons of electricity commodity changes alone against a Hydro Ottawa bill that includes distribution and other charges
- (As described above in 5.3.3) comparisons between pricing structures that are designed to be revenue neutral for an entire year, but have different effects on individual months
- Finally, comparisons that do not consider the bill reductions resulting from the average conservation effect realized by participants on TOU prices.

Information Provision

Participants in the focus groups and survey respondents particularly valued the monthly usage statement and refrigerator magnet as the most useful resources to help understand the TOU prices, overshadowing the fact sheet, brochure, or any other pilot communications materials.

There was a consensus among focus group participants that bi-monthly billing frequency was not adequate within the context of smart meters and TOU pricing.

Nearly 70% of survey responses did indicate that they anticipate accessing an online statement at least monthly.

Pricing Structure Feedback

The consensus feedback among focus group participants was that the TOU pricing structure was easy to understand and did not need to change:

- When asked if they would prefer only two TOU periods (off- and on-peak, without mid-peak), none of the focus group participants said they desired a change to a two-period TOU structure from the current three-period TOU structure
- For the most part (71%), survey respondents felt that the difference in price points was large enough to encourage them to shift their electricity consumption.

1 Introduction

This report summarizes the design, operation and outcomes of the Ontario Energy Board Smart Price Pilot (OSPP) undertaken by the Ontario Energy Board (the Board) from August 1, 2006 to February 28, 2007. The OSPP tested the reactions and impacts on consumer behaviour of three different price structures:

- Time-of-use (TOU) prices
- TOU prices with a critical peak price
- TOU prices with a critical peak rebate

The pilot was initiated in mid June of 2006 and recruited participants were placed on the TOU prices starting on August 1, 2006. Originally the pilot was intended to end on December 31, 2006, but the Board subsequently decided to extend the pilot period until February 28, 2007 to capture the coldest winter months.

Outcomes are measured through the quantitative analysis of demand response, total electricity conservation, and participant survey responses. Qualitative feedback was garnered from focus groups and tracking of participant support calls.

1.1 Background

The Government of Ontario has committed to install a smart electricity meter in 800,000 homes and small businesses by 2007, and throughout Ontario by 2010. The continued installation of smart meters will ultimately enable the application of TOU pricing, as set by the Board, to all electricity consumers on the Regulated Price Plan (RPP), i.e., those consumers not on a retailer contract. Virtually all RPP consumers in Ontario currently pay two-tiered threshold (non-TOU) prices.

Since the RPP was introduced in April 2005, Ontario distributors were permitted to make TOU pricing mandatory for their customers with smart meters. Milton Hydro is the only Ontario utility that has opted to implement RPP TOU pricing on a relatively large scale for its customers with smart meters. Milton Hydro first implemented TOU pricing in October 2005 and currently has about 5,000 RPP TOU customers. The plan is to have over 15,000 customers on RPP TOU pricing by the end of the year.

Chatham-Kent Hydro is already implementing TOU pricing on a small scale. On March 23, 2007, the first TOU bills were issued to 215 customers for the January 2, 2007 to March 6, 2007 read dates.

Implementation of TOU pricing on a mandatory, Province-wide basis for consumers with smart meters has been deferred pending the further deployment of smart meters. The installation of smart meters and their enrolment into the provincial meter data management and repository (the "MDM/R") is being done on a phased basis. The MDM/R is currently under development by the Independent Electricity System Operator (IESO) and will be eventually operated by the Smart Metering Entity (SME).

The complete services to be provided or offered by the SME through the MDM/R have yet to be determined. Regulations currently contemplate that the SME will perform the following meter data functions:

- Verification, validation and editing of meter data received from distributors
- Processing and aggregation of meter data into price periods that is ready for billing purposes
- Storing and maintaining of meter and associated data

Deferral of mandatory TOU pricing has provided the Board with an opportunity to initiate the OSPP to test different time-sensitive price structures for RPP consumers. The Board also hopes to gain further insights into how consumers respond to TOU prices, prior to their large-scale introduction in Ontario.

As part of the initial development of the RPP, the Board's RPP Proposal of December 2004 made a commitment to investigate the feasibility of implementing a critical peak pricing component to supplement the TOU RPP prices. This commitment specifically identified pilot projects as part of the investigation.

1.2 Pilot Objectives

The Ontario Energy Board Smart Price Pilot is intended to assess:

- The extent to which various time-sensitive pricing structures cause a shift of electricity consumption to Off-Peak periods as measured by the reduction in peak demand
- The extent to which each price structure causes a change in total monthly electricity consumption
- The understandability of and acceptability by residential consumers of each pricing structure and the communications associated with each

The results in this report are intended to inform the Board with respect to future decisions associated with CPP and CPR as well as whether refinements are needed to the current RPP TOU pricing construct and associated consumer communications.

1.3 Other Ontario TOU Pricing Pilots

In parallel with initiating this pilot, the Board also issued Standard Supply Service Code (the "SSS Code") amendments that permit other Ontario distributors to implement similar TOU pricing pilots where they are complementary to the OSPP.

As of June 2007, the Board had approved pilot programs of four distributors under section 3.9.1 of the SSS Code.

1.3.1 Newmarket Hydro

Newmarket Hydro is operating a pilot project involving smart thermostats in conjunction with RPP TOU pricing and Critical Peak Rebates (CPR). In October 2006, 253 participants began to receive TOU bills. The pilot is scheduled to run until the end of October 2007. Notification for CPR events will be a mix of "day of" or "day before" a CPR period. The same critical peak price of 30¢/kWh is being used. Newmarket Hydro will automatically control the air conditioners of some participants using programmable thermostats during summertime critical periods. No CPR or thermostat control events have been conducted as yet (other than a technical test in November). The participants are included in six treatment groups based on combinations of being placed on CPR prices, exposed to enhanced education, and provided with a programmable thermostat.

1.3.2 Oakville Hydro

Oakville Hydro's TOU pricing pilot project involves sub-metered residential condominiums. This project will allow the Board to assess the impact on consumption of sub-metering a bulk metered condominium alone and then the incremental impact of applying RPP TOU prices. As of December 2006, 370 participants in three condominiums had been recruited.

1.3.3 Veridian Connections

Veridian Connections is operating a TOU pricing pilot project involving medium-sized business consumers. In total, 55 customer accounts with peak demand greater than 200 kW are taking part in the pilot. In aggregate, these customers represent peak demand of approximately 20 MW and annual consumption of 140 GWh. The pilot started in March 2007 and will run through to September 2007. It will allow for a direct comparison of the price elasticity of general service consumers with that of residential consumers in the other OEB-approved pilots. The results of the Veridian pilot could also be extrapolated to similar consumers of other distributors and will help inform the communication efforts of the Board, the IESO, and other electricity distributors to those designated consumers who are expected to be ineligible for RPP prices after April 1, 2008.

1.3.4 Hydro One

Hydro One's TOU pricing pilot project involves about 500 residential, farm and small business consumers and real-time in-home display monitors (as well as smart thermostats). This pilot is currently in the recruitment phase and implementation is planned over the summer of 2007.

About half of the pilot participants will not receive the in-home display monitors which will allow for a comparison between customers with and without such monitors. Participants will be asked to fill out two questionnaires during the pilot (one at the beginning and the other at the end of the pilot) to gather further information about appliance and equipment usage as well as actions taken to change the consumption patterns during the pilot project. This is intended to help better understand the reasons for potential changes in the hourly electricity consumption patterns.

1.3.5 Peterborough Distribution Inc

In addition to the above pilots approved under section 3.9.1 of the SSS Code, Peterborough Distribution Inc. (PDI) has been conducting a pilot program on TOU prices since 2005 in conjunction with two of its conservation and demand management (CDM) programs. PDI has been billing TOU prices to about 200 customers for over two years. (This pilot was approved by the Board as part of PDI's CDM plan prior to the Board's issuance of SSS Code amendments requiring approval of pilot projects involving RPP TOU pricing.)

Thermal Storage Heating for Social Housing

PDI provided financial, technical and administrative expertise to convert 124 electrically heated social housing units from baseboard electric heating to electric thermal storage heaters. The storage heaters use electricity in Off-Peak periods and store that heat in specially designed ceramic bricks for use during On-Peak periods. As such, consumption during On-Peak periods is at Off-Peak prices. Based on calculations using the methodology in the Board's TRC guide for annual CDM filings, the consumption shifted from On-Peak to Off-Peak is calculated to be 4 million KWh over the 18 year life of the 124 units. The estimated savings to the City of Peterborough's Housing Corp. is $47,500 per year.

Residential Appliance Controllers

A radio signal control system is used to control residential appliances (A/C, hot water tanks, pool pumps, clothes washers, dryers, dishwashers). The controller causes a shift in discretionary use of electricity to Off-Peak times. This CDM program, currently controlling 314 appliances for 200 residential customers, is estimated to be reducing summer peak by 155 kW and winter peak by a further 645kW. Energy savings are estimated at over $896,000 over the 12 year life of the 200 controllers.

With the availability of smart metering and TOU prices, customers are volunteering to participate in this CDM initiative.

1.3.6 Summary

Together, these pilot projects cover the spectrum in terms of consumer groups currently eligible for RPP (residential in homes and condominiums, farms, small businesses and medium-size businesses). In addition, the first three pilots involve consumers in *urban* areas, while the consumers in Hydro One's pilot are in *rural* areas.

The initial distributor proposals, the Board Decision on each and (as they become available) final outcomes for these pilots are available on the OEB's website, on the same web page dedicated to the OSPP project, at
www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_regulatedpriceplan_smartpricepilot.htm

2 Price Design

Three different commodity price structures were tested during the pilot:

- The existing RPP TOU prices
- The existing RPP TOU prices with a critical peak price
- The existing RPP TOU prices with a critical peak rebate

Participant usage on these three price plans was compared with the usage of customers in a fourth “control” group who also have smart meters but remained on the two-tiered RPP prices.

The three price structures are designed to be as revenue neutral as possible relative to each other. This is defined such that a participant whose electrical usage is distributed across the hours in the same way as the provincial average for all RPP consumers will pay approximately the same bill on all three options in the absence of any change in usage. This revenue neutral approach is the same design used in the California Statewide Pricing Pilot and the PowerCentsDC pilot in Washington D.C. By controlling for total bill amounts prior to demand response to the prices, the revenue neutral design allows for a more accurate comparison of the demand response effects associated with the three price designs tested.

All RPP TOU prices were adjusted during this pilot for all three groups to reflect changes to the RPP prices applied across the province on November 1, 2006. This change in RPP prices was relatively minor. As such, the critical peak price and rebate amount remained the same throughout the pilot. This change is important to continue a valid comparison against the prices charged to the control group.

All prices on the pilot are related solely to the commodity portion of a customer’s electricity bill; delivery, debt retirement, and other charges were not changed as a result of the pilot.

All three price structures tested in the pilot are described in more detail below.

2.1 Tiered Prices for Control Group

The conventional meter RPP has prices in two tiers, one price for monthly consumption under a tier threshold and a higher price for consumption over the threshold. The thresholds for residential consumers vary by season:

- 600 kWh per month during the summer season (May 1 to October 31)
- 1000 kWh per month during the winter season (November 1 to April 30).

The two-tiered RPP prices in effect during the pilot period and applied to all control group customers are provided in Exhibit 1.

Summer (Aug 1 – Oct 31)	Price/ kWh	Winter (Nov 1 – Feb 28)	Price/ kWh
First 600 kWh per month	5.8¢	First 1,000 kWh per month	5.5¢
Remaining kWh	6.7¢	Remaining kWh	6.4¢

Exhibit 1: Tiered RPP prices applicable to all RPP consumers in Ontario and paid by control group customers.

The rationale for tiered pricing was to provide a price signal to consumers to conserve until such time as smart meters are installed and TOU pricing can be applied across the province.

The tier thresholds are set such that there is roughly a 50/50 split of forecast consumption at the lower tier price and at the higher tier price, resulting in tiered prices that are distributed symmetrically around the average RPP supply cost. [5]

The two-tiered RPP prices and the RPP TOU prices are established based on the same average RPP supply cost (or average RPP price) as shown in Exhibit 2 for the most recent RPP prices as of May 1, 2007. The breakdown by TOU period (i.e., % of consumption) is based on the load profile used for all RPP consumers.

Tiered RPP Prices	Tier 1		Tier 2	Average Price
Price	5.3¢		6.2¢	5.7¢
% of Consumption	53%		47%	
Time-of-Use RPP Prices	**Off-Peak**	**Mid-Peak**	**On-Peak**	**Average Price**
Price	3.2¢	7.2¢	9.2¢	5.7¢
% of Consumption	48%	29%	23%	

Exhibit 2: Tiered and TOU RPP prices are both based on the same average RPP supply cost.

5 - See Ontario Energy Board, "Regulated Price Plan Price Report May 1, 2006 to April 30, 2007," April 12, 2006, for details. It is available at www.oeb.gov.on.ca/documents/cases/EB-2004-0205/rpp_pricereport-may06-apr07_120406.pdf

2.2 RPP Time-of-Use (TOU) Prices

The existing RPP TOU prices and hours alone (without any critical peak adjustments) were used for one of the treatment groups in the pilot. These prices reflect the changes to the RPP prices that came into effect November 1, 2006.

Time	Summer Hours (Aug 1 - Oct 31)	Price/ kWh	Winter Hours (Nov 1 - Feb 28)	Price/ kWh
Off-Peak	10 pm - 7 am weekdays; all day on weekends and holidays	3.5¢	10 pm - 7 am weekdays; all day on weekends and holidays	3.4¢
Mid-Peak	7 am - 11 am and 5 pm - 10 pm weekdays	7.5¢	11 am - 5 pm and 8 pm - 10 pm weekdays	7.1¢
On-Peak	11 am - 5 pm weekdays	10.5¢	7 am - 11 am and 5 pm - 8pm weekdays	9.7¢

Exhibit 3: RPP TOU prices are unchanged from the Board set prices

2.3 Critical Peak Pricing

As with RPP TOU prices, the Critical Peak Price was designed to be as revenue neutral as possible. The critical peak price was determined to be the average price of the highest 93 hours between June 2005 and June 2006, based on the hourly Ontario electricity prices (the HOEP).

The applicable RPP TOU prices and hours were used for all non-critical hours during the pilot; however, the Off-Peak price was reduced to 3.1 ¢/kWh to offset the increase in the Critical Peak Price of 30 ¢/kWh.

The resulting prices are shown in Exhibit 4.

Time	Summer Hours (Aug 1 - Oct 31)	Price/ kWh	Winter Hours (Nov 1 - Feb 28)	Price/ kWh
Off-Peak	10 pm - 7 am weekdays; all day on weekends and holidays	3.1¢	10 pm - 7 am weekdays; all day on weekends and holidays	3.1¢
Mid-Peak	7 am - 11 am and 5 pm-10 pm weekdays	7.5¢	11 am - 5 pm and 8 pm-10 pm weekdays	7.1¢
On-Peak	11 am - 5 pm weekdays	10.5¢	7 am - 11 am and 5 pm-8pm weekdays	9.7¢
CPP	3 to 4 hours during On-Peak, invoked up to 9 times during the pilot	30.0¢	3 to 4 hours during On-Peak, invoked up to 9 times during the pilot	30.0¢

Exhibit 4: Critical Peak Prices. The Off-Peak price is reduced under Critical Peak Prices

The CPP represents about a three-fold increase over the On-Peak price. The reason for the different percentage amounts (in terms of the reduction in the Off-Peak price versus the increase from the On-Peak price to the Critical Peak Price) is that critical peak prices are in effect during the few hours when critical events are declared, while Off-Peak prices are in effect for over 4,700 hours (or over half of all hours).

Critical peak pricing only occurs for 3 or 4 hours during the On-Peak period, on critical peak days only. The maximum number of critical peak days planned for the pilot was nine.

2.4 Critical Peak Rebate

The OSPP also tests the impacts of a Critical Peak Rebate (CPR) pricing structure. In contrast to the CPP, the CPR provides a refund to participants for reductions below their "baseline" usage during the critical peak hours.[6] To strive for revenue neutrality, the rebate amount was set to be the same as the Critical Peak Price during critical peak hours. Also, since the incentive during the critical peak hours is a rebate, there is no adjustment in the Off-Peak price. A participant making no change in response to the critical peak events will pay the same bill on TOU plus CPR as they would if they were a participant on TOU-only prices.

The existing RPP TOU prices and hours were used during the pilot. As for CPP above, Critical Peak rebates were in effect only when critical events were declared, a maximum of nine events were planned during the pilot and only for three or four hours during On-Peak hours.

2.4.1 Baseline Determination

For a participant to receive a rebate, their consumption had to be below a baseline. This means that the higher the baseline, the easier it is for a participant to earn a rebate (i.e. use an amount of electricity less than the baseline amount).The baseline methodology was developed by reviewing other baseline methodologies used for other residential CPR programs, as well as baselines used for large commercial consumer curtailable programs. Baseline methods considered were the following:

- PJM Interconnections: Usage for the same hours in the three highest of the ten previous non-event, non-holiday weekdays
- New York Independent System Operator: Five highest of the ten previous non-event, non-holiday weekdays
- Anaheim Public Utilities: Three highest non-event, non-holiday weekdays in the first half of summer
- PowerCentsDC pilot in Washington D.C.: Three highest non-event, non-holiday weekdays in the previous month

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6 - See Appendix A, Analysis of Critical Peak Rebate Program Concept.

- San Diego Gas & Electric (SDG&E): Average of previous five non-event, non-holiday weekdays

The SDG&E approach is the most recently developed and was based on a detailed analysis of residential consumer data. Its advantage is its computational simplicity. However, because critical days are, by definition, the most extreme, SDG&E's baseline approach understates what the consumer would have otherwise used on critical days.[7] This artificially low baseline means that a customer would have to reduce peak consumption on critical days just to reach the baseline level — then further reduce consumption to earn a rebate (and certainly resulting in consumer frustration).

The team analyzed data for 2005 from a similar Anaheim TOU pilot and determined that, on average, usage of control group consumers during critical peak periods was 23% higher than their average usage during the same hours of the five previous non-event, non-holiday weekdays. In other words, this data showed that the starting point for determining a load reduction should be 23% above the five-day average, giving the customer a greater (and appropriate) opportunity to earn a rebate. Based on this analysis, a rounded-off adjustment factor of 25% was used for the OSPP.

The OSPP baseline approach gains the benefits of the San Diego method while using the adjustment factor to remove the inherent customer penalty.

The result is a baseline that is calculated as the average usage for the same hours of the five previous non-event, non-holiday weekdays, multiplied by 125%. The difference between the consumer's consumption during the Critical Event and the baseline would be subject to the CPR, creating a rebate of 30 ¢/kWh times the amount by which the participant's usage was reduced. (See Exhibit 5 for an illustration.)

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[7] - For a detailed discussion of baseline issues see Xenergy, "Protocol Development for Demand Response Calculation," Prepared for California Energy Commission, August 1, 2002.

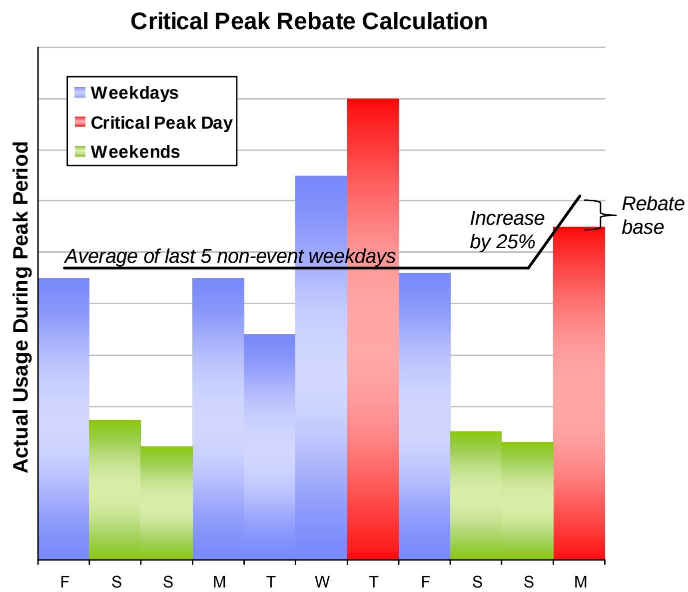

Exhibit 5: A participant's CPR baseline is determined as the average of usage during the same hours over the participant's last five, non-event weekdays, increased by 25%. The rebate is calculated as the kWh difference between the participant's CPR baseline and their actual usage on the day (the rebate base) multiplied by 30¢.

The resulting prices are provided in Exhibit 6.

Time	Summer Hours (Aug 1 - Oct 31)	Price/ kWh	Winter Hours (Nov 1 - Feb 28)	Price/ kWh
Off–peak	10 pm-7 am weekdays; all day weekends and holidays	3.5¢	10 pm-7 am weekdays; all day weekends and holidays	3.4¢
Mid–peak	7 am-11 am and 5 pm-10 pm weekdays	7.5¢	11 am-5 pm and 8 pm-10 pm weekdays	7.1¢
On-peak	11 am-5 pm weekdays	10.5¢	7 am-11 am and 5 pm-8pm weekdays	9.7¢
CPR	3 to 4 hours during On-Peak, invoked up to 9 times during the pilot	30.0¢	3 to 4 hours during On-Peak, invoked up to 9 times during the pilot	30.0¢

Exhibit 6: Critical Peak Rebate prices, where the RPP TOU prices are unchanged

2.5 Critical Peak Trigger

The team considered two approaches for triggering critical peak events. The first was to dispatch in parallel with the Independent Electricity System Operator's (IESO) voluntary Emergency Load Reduction Program, for which only large wholesale market consumers are eligible. For this program, the IESO forecasts day-ahead supply and demand and calls an event when forecast supply margins are very low. However, because this is designed to be an emergency program, it is intended to be triggered relatively infrequently (i.e., only a handful days per year are expected).

While this may be appropriate for the long term (perhaps if and when CPP is implemented province-wide), the short pilot schedule made it necessary to consider a weather trigger to increase the likelihood that a sufficient number of events would be called during the pilot period to provide the necessary data for analysis.

A weather trigger is commonly used in critical peak programs. The trigger is calculated based on historical data to determine how many times a particular temperature was exceeded (on the high side in summer, low side in winter). The team reviewed historical data for the past five years and selected temperatures which would have provided an appropriate number of critical peak events in at least four of the past five years. See Appendix B for details of the analysis.

A conservative approach was taken in selecting the trigger temperatures because, if the threshold is exceeded too many times, events need not be called (whereas if not enough events occur, insufficient data will be available for analysis).

The trigger temperatures selected were 28°C in summer and -14°C in winter. In addition, events would be called when the Humidex exceeds 30°C during On-Peak times of the day, regardless of the temperature.

3 Participant Population

3.1 Participating Distributor

To conduct the pilot, the Board needed a Ontario electricity distributor to provide candidate customers, interval meter data, and ongoing communications support. Among a variety of candidates, Hydro Ottawa was selected as the participating distributor for the following reasons:

- Hydro Ottawa had a sufficient number of smart meters installed and operating, which thus provided a suitable population from which to recruit participants prior to the start of the pilot in August 2006.
- Hydro Ottawa is expected to be a key contributor in the initial implementation of smart meters in Ontario, with plans to install some 130,000 meters by the end of 2007. This meant that the results would be directly applicable to a large number of consumers in the same area expected to soon be on time-sensitive prices.
- Two characteristics of Hydro Ottawa meant that results could potentially be appropriately generalized to RPP-eligible consumers of other Ontario distributors, particularly those installing smart meters in 2007 (mostly in the Greater Toronto Area or GTA):
  - The candidate customers are in a variety of neighbourhoods with a range of monthly electricity consumption, major appliance holdings, housing types, housing ages, and family incomes.
  - The Ottawa area climate was conducive to the pilot objectives: summertime temperature highs are nearly identical to those in the GTA and wintertime lows are lower. This is important, because research indicates that the greatest response to time-based pricing occurs at extreme temperatures.[8] These responses are greater in both absolute and relative terms. Moderate weather also occurs in Ottawa. The pilot is designed to measure demand response on an hourly basis, taking advantage of the hourly data available from the smart meters. The hourly analysis allows for estimating the demand response (and extrapolation to other locations) on moderate days and extreme days. To the extent one area, such as the GTA, has more of the extreme days, this can be accounted for in the extrapolation through weighting the results by the number of extreme days versus moderate days.

[8] See for instance, Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot, Final Report," February 11, 2005.

- Hydro Ottawa management committed support to the pilot, funding necessary internal operations and the thank you payments provided to participating customers.

3.2 Customer Participation

Candidate participants were randomly selected from the population that would have smart meters installed in Hydro Ottawa's territory by August 1, 2006. The experimental design was a classic side-by-side comparison of control group versus treatment groups. Participants were recruited for the three treatment options:

- Time-of-use (TOU) only
- TOU plus Critical Peak Pricing (CPP)
- TOU plus Critical Peak Rebate (CPR)

Participants were segregated by price structure. The participants were recruited independently and had no knowledge of the price structures offered to other customers. Participants were recruited using a stratified random sample to ensure that a sufficient number of participants were in each of the low, medium, and high monthly consumption groups.

Recruitment was undertaken via direct mail, using a letter co-branded by Hydro Ottawa and the OEB. (Subsequent pilot communications were branded as OEB communications.) The initial letter notified customers that they "have been selected as a participant." However, customers were not included in the pilot unless they returned the confirmation form included in the recruitment mailing. One reason confirmation was needed was to provide the correct telephone number or email address for critical peak event notifications.

3.2.1 Control Group

The control group was a sample of 125 customers selected randomly from the population of Hydro Ottawa residential customers who had smart meters installed prior to the August 1, 2006 start of the pilot but continued to pay tiered (non-TOU) prices.

All treatment and control participants were RPP consumers (i.e., not on a retailer contract).

3.3 Recruitment Results

In a marked difference from other residential TOU pilot projects, the OSPP was over-subscribed after only one recruitment solicitation and within about one week. While a 10% enrolment rate was expected, in fact, out of 1,800 recruitment letters sent (600 for each targeted price group), 459 people responded by submitting an enrolment form, a 25.5% response rate. Another 50 customers contacted the customer support staff by email and telephone, in most cases after the enrolment deadline. If all 50 of these additional customers had been enrolled, the total response rate would have been 28.3%. A contingency recruitment mailing, common in other pilot projects, was not necessary in this case.

The table below shows the OSPP results compared to some other pilots. Note that consumers in the California Pilot were contacted by phone as well as mail, whereas the OSPP recruitment was limited to a single mailing.

Program	Year	Enrolment Rate
OSPP (1 mailing)	2006	25.5-28.3%
California Statewide Pricing Pilot[9] (2 mailings and 3 phone calls)	2003-2005	20.3%
Idaho Power Time-of-Day and Energy Watch (1 mailing)	2005	3.5%

Exhibit 7: A participant response rate of at least 25% on the first mailing is significantly greater than past pilots with which we are familiar.

Potential reasons for the high recruitment response rate are discussed in the discussion of focus group results, presented in Section 6.1.

Originally, 75 participants were targeted for each treatment group. However, given the response, the Board and Hydro Ottawa decided to increase funding and expand the project to 125 participants in each price group. Of the customers who had hoped to enrol in the pilot, 84 were declined participation. One customer was added to the TOU group as a concession to their persistence, making the total number of TOU participants 126. However, upon initial pilot operation meter data was not available for three customers due to technical issues. The precise number of participants resulting in the three pricing groups is in Exhibit 8.

Price Treatment Group	Number of Participants
TOU	124
CPP	125
CPR	124
Total	373

Exhibit 8: Number of pilot participants by price treatment

3.4 Participant Characteristics

Participants were asked to complete an appliance survey upon registration. More detailed appliance usage and household characteristics data were gathered in a

[9] The California Recruitment included two mailings and three phone calls per customer.

subsequent survey of the pilot participants (with a 79% response rate) in November. The relevant results of the surveys are provided in the tables below, compared against the average for Hydro Ottawa and all of Ontario.

Except where noted, all Ottawa and Ontario data are based on the 2001 Census. All comparisons with pilot participants are therefore affected by the 5-year difference in the data. Specific adjustments made to compensate for this difference are noted.

3.4.1 Heating and Cooling Characteristics

The results in Exhibit 9 show that the cooling characteristics of participants in the pilot project are very consistent with the Hydro Ottawa population, and to a lesser extent with the Ontario population at large. The space heating characteristics of the pilot participants are quite close to the provincial figures in terms of natural gas versus electric heating, as well as the percentage with electric water heating.

Also, while air conditioning penetration rates appear greater among pilot participants compared to 2003 data for Ontario as a whole, the Office of Energy Efficiency of Natural Resources Canada estimates that central air conditioning penetration is increasing in Ontario at 4.1% per annum, which would mean a 2006 penetration rate of approximately 65%.[10]

<table>
<tr><th>Space Cooling</th><th>TOU</th><th>CPP</th><th>CPR</th><th>Total</th><th>Pilot %</th><th>Ottawa % [11]</th><th>Ontario % [12]</th></tr>
<tr><td>Central Air Conditioning</td><td>106</td><td>109</td><td>104</td><td>319</td><td>85.1%</td><td>76.5%</td><td>57.6%</td></tr>
<tr><td>Window Air Conditioning</td><td>9</td><td>6</td><td>7</td><td>22</td><td>5.9%</td><td>8.9%</td><td rowspan="2">16.1%</td></tr>
<tr><td>Ductless A/C / Wall Mounted</td><td>1</td><td>0</td><td>0</td><td>1</td><td>0.3%</td><td>n/a</td></tr>
<tr><td>No Air Conditioner</td><td>8</td><td>10</td><td>14</td><td>32</td><td>8.5%</td><td>12.6%</td><td>26.3%</td></tr>
<tr><td>No response</td><td>1</td><td>0</td><td>0</td><td>1</td><td>0.3%</td><td>n/a</td><td>n/a</td></tr>
<tr><th>Space Heating</th><th>TOU</th><th>CPP</th><th>CPR</th><th>Total</th><th>Pilot %</th><th>Ottawa %</th><th>Ontario %</th></tr>
<tr><td>Gas Space Heating</td><td>101</td><td>101</td><td>105</td><td>307</td><td>82.3%</td><td>86.7%</td><td>82.6%</td></tr>
<tr><td>Electric Space Heating</td><td>11</td><td>11</td><td>10</td><td>32</td><td>8.6%</td><td>3.4%</td><td>7.3%</td></tr>
<tr><td>Other</td><td>0</td><td>1</td><td>0</td><td>1</td><td>0.3%</td><td>9.9%</td><td>10.1%</td></tr>
<tr><td>None</td><td>0</td><td>1</td><td>0</td><td>1</td><td>0.3%</td><td>0.0%</td><td>0.0%</td></tr>
<tr><td>No response</td><td>11</td><td>11</td><td>10</td><td>32</td><td>8.6%</td><td>n/a</td><td>n/a</td></tr>
</table>

[10] Source: Modelling and Scenario Documentation, Prepared by M.K. Jaccard and Associates for the OPA.

[11] Source: Hydro Ottawa customer survey which was designed to be within +/- 3% accurate 95% of the time.

[12] Source: Office of Energy Efficiency, Natural Resources Canada “2003 Survey of Household Energy Use”.

Water Heating	TOU	CPP	CPR	Total	Pilot %	Ottawa %	Ontario %
Gas or Oil Water Heating	105	108	104	**313**	**84.4%**	82.7%	85%
Electric Water Heating	17	15	20	**52**	**14.0%**	16.2%	15%[13]
No response	3	2	1	**6**	**1.6%**	n/a	n/a

Exhibit 9: Based on a survey upon enrolment, the cooling methods of pilot participants is very consistent with the Hydro Ottawa population, and to a lesser extent with the Ontario population at large. The heating methods are quite consistent.

3.4.2 Housing Characteristics

Comparisons of housing type across data sources are problematic. The Ontario average is based on the Statistics Canada surveys sampled from all Ontario households. In contrast the population of electric utility consumers in Ontario will not include apartments and other units not individually metered by the distributor.

Regarding housing age, 72% of the homes in the pilot were built after 2001. While Ottawa and provincial data are from the 2001 Census, it is clear that this is not representative of the provincial housing stock. However, at the start of the pilot, Ottawa did offer one of the most diverse populations available of housing ages with smart meters installed in Ontario.

Housing Type	TOU	CPP	CPR	Total	Pilot %	Ottawa %[14]	Ontario %[14]
Single-family home	106	100	101	**307**	**81.9%**	54.4%	69.4%
Apartment or Condominium (Under 5 storeys)	13	15	16	**44**	**11.7%**	15.7%	30.6%
Townhouse	4	9	7	**20**	**5.3%**	22.6%	
Duplex	1	0	0	**1**	**0.3%**	7.3%	
No response	1	1	1	**3**	**0.8%**	n/a	n/a
Housing Age	**TOU %**	**CPP %**	**CPR %**	**Total %**		**Ottawa %**	**Ontario %**
Before 1970	2	2	5	3		42	49
1971 to 1980	1	1	3	2		22	19
1981 to 1990	3	0	3	2		21	18
1991 to 2000	17	23	24	22		14	14
After 2001	77	74	65	72		n/a	n/a

Exhibit 10: Housing type and housing age comparisons between pilot participants and the Ottawa and provincial populations.

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13 Source: Electricity Demand in Ontario – A Retrospective Analysis, ICF Consulting, Revised November 2005 (prepared for the Chief Conservation Officer, OPA).

14 Source: Statistics Canada Community Profiles 2001. Does not including "Apartment in a building that has five or more storeys"

3.4.3 Socioeconomic Status

The survey data helps further profile pilot participants against the Ottawa and provincial populations (see Exhibit 11). Pilot participants are generally more educated and have a higher household income than the general population of Ottawa. There is less of a difference in income compared to the province, as Ottawa has a higher percentage of lower income households than the province.

Household income is based on income for private households in the 2001 census. It has been adjusted for inflation.

Education	TOU %	CPP %	CPR %	Total %	Ottawa %[15]	Ontario %
Some High School	2	2	1	1	12	20
High School Graduate and/ or Some Postsecondary	22	13	14	16	25	27
University or College Graduate	76	85	85	83	63	53
Household Income	**TOU %**	**CPP %**	**CPR %**	**Total %**	**Ottawa %**	**Ontario %**
Less than $50,000	9	10	13	11	30	18
$50,000 to $100,000	49	40	30	43	40	47
More than $100,000	41	50	49	47	30	35

Exhibit 11: Comparisons of education and income levels between the pilot participants and the Ottawa and Ontario averages.

3.5 Control Group

To create the control group, 125 customers were selected in a stratified random sample from approximately 4,500 customers with smart meters. The 4,500 customer-pool included three groups:

- Approximately 3,200 customers who had not been solicited to participate
- An estimated 900 customers who had been solicited but did not read the solicitation (i.e. were unaware of it[16])
- An estimated 400 customers who had been solicited and decided not to volunteer for the pilot.

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[15] Data for both Ottawa (the Ontario part of Ottawa/Hull CMA) and Ontario in this table are based the 2001 census from Statistics Canada.

[16] In the California Statewide Pricing Pilot, the participating utilities reported that only 31% of customers were aware of the opportunity to participate in the pilot, in spite of receiving three mailings and three attempted phone calls. The estimate above uses the 31% figure. This is likely quite conservative, as there was only one mailing in the OSPP.

Thus, less than 10% of the control group were customers who consciously decided not to participate, and the control group behaviour serves as a relatively good proxy for electricity consumption behaviour of the Hydro Ottawa residential population as a whole.

4 Pilot Operation

This section describes the operational details of the pilot, including participant communication approaches, billing approach, critical peak notifications and participant support.

4.1 Participant Recruitment Materials

The recruitment packages consisted of the following:

- *Cover Letter*: Provides a brief introduction to the pilot, describes key features, and informs eligible participants how to confirm participation.
- *Fact Sheet*: Provides an explanation of all the key features of the pilot, shows the specific TOU prices, provides a sample of the monthly electricity usage statement to be received by participants (see Exhibit 12), and provides a sample of the final settlement that will be provided to participants.
- *Confirmation Form*: When signed, this form confirms the customer's participation and provides needed authorization for pilot data handling and analysis.

There are three versions of the Letter and Fact Sheet; one per price design group. All materials are provided in both English and French. Sample recruitment materials are included in Appendix C.

4.2 Customer Education

Initial participant education, beyond the material in the recruitment package, focused on a package mailed to each eligible participant following receipt of their enrolment form. This confirmation mailing included the following:

- *Cover Letter*: Confirms that the participant is enrolled.
- *Refrigerator magnet:* Provides a table of the prices, times, and seasons for the participant's price plan. The magnet to be sent is an adaptation of a design that was preferred by customers in focus groups conducted for a different pilot program by Hydro Ottawa. (See Exhibit 13.)
- *Electricity conservation brochure*: This PowerWise brochure provides a variety of conservation tips for electricity consumers that may be used during peak times or anytime.

A sample of the complete Confirmation Package materials is provided in Appendix D.

HydroOttawa

Ontario Smart Price Pilot

Sample Electricity Usage Statement

Ontario Smart Price Pilot
Time-of-Use Electricity Usage Statement
Note: this is not a bill

Account

John Doe
123 Main St SE
Ottawa

Account Number
ABC-12344567

24 hr Customer Service
1-800-xxx-xxxx

Price Season:
Summer

Price Definitions

Off Peak
Price for usage from 10 pm-7 am weekdays and all day, weekends and holidays

Mid Peak
Price for usage from 7 am-11 am & 5 pm-10 pm weekdays

On Peak
Price for usage from 11 am-5 pm weekdays

Critical Peak Rebate
Rebate for *reductions* during critical peak hours (3 or 4 hours during the on-peak period, upon notification)

Critical Peak Days This Month

August 10, 2006
August 11, 2006
August 29, 2006

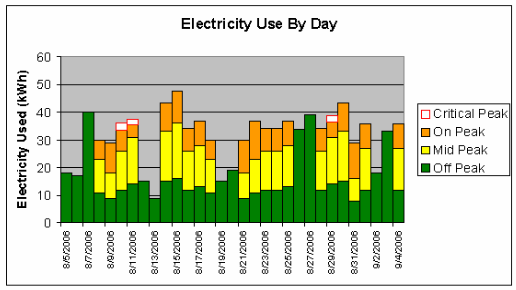
ELECTRICITY USE

Electricity	Service Dates	Usage
On Peak	8/05/2006 To 9/04/2006	200 kWh
Mid Peak	8/05/2006 To 9/04/2006	300 kWh
Off Peak	8/05/2006 To 9/04/2006	500 kWh

Total Electricity Use **1,000 kWh**

Critical Peak Usage Reduction	Dates	Reduction
Critical Peak	8/10/2006	2.5 kWh
Critical Peak	8/11/2006	2.1 kWh
Critical Peak	8/29/2006	2.4 kWh

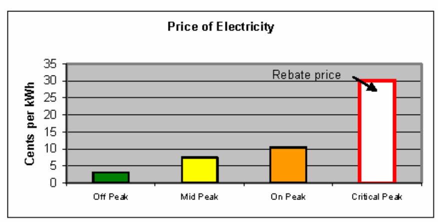
Total Reductions for Rebate **7.0 kWh**



TIME-OF-USE CHARGES (Electricity Only, excludes taxes & other)

Electricity	Price	kWh	Amount
Critical Peak	30.0 cents per kWh	7	-$2.10
On Peak	10.5 cents per kWh	200	$20.27
Mid Peak	7.5 cents per kWh	307	$23.03
Off Peak	3.5 cents per kWh	500	$17.50

Total Time-of-Use Charges ***(Do Not Pay)*** **$58.69**



Sample Smart Price Pilot Program Final Statement – Customer with *Savings* on Time-of-Use Prices

Exhibit 12: Sample of Electricity Usage Statements provided monthly to all participants; the statements differed slightly to reflect the differences between TOU, CPP, and CPR prices.

HydroOttawa

Ontario

ONTARIO SMART PRICE PILOT / PROJET PILOTE DE PRIX INTELLIGENT

TIME OF USE PERIODS AND RATES / PÉRIODES D'UTILISATION ET PRIX

Day of the Week Jours de la semaine	Time Heures	Time of Use Périodes d'utilisation	Price/Prix* (¢/kWh)
Weekends & Holidays Fins de semaine et fériés	All Day / Toute la journée	Off-peak / Période creuse	3.5 ¢
Summer Weekdays (May 1st - Oct 31st) Jours de semaine l'été (du 1er mai au 31 octobre)	7 am to 11 am / 7 h à 11 h	Mid-peak / Période moyenne	7.5 ¢
	11 am to 5 pm / 11 h à 17 h	On-peak / Période de pointe	10.5 ¢
	5 pm to 10 pm / 17 h à 22 h	Mid-peak / Période moyenne	7.5 ¢
	10 pm to 7 am / 22 h à 7 h	Off-peak / Période creuse	3.5 ¢
Winter Weekdays (Nov 1st - Apr 30th) Jours de semaine l'hiver (du 1er novembre au 30 avril)	7 am to 11 am / 7 h à 11 h	On-peak / Période de pointe	10.5 ¢
	11 am to 5 pm / 11 h à 17 h	Mid-peak / Période moyenne	7.5 ¢
	5 pm to 8 pm / 17 h à 20 h	On-peak / Période de pointe	10.5 ¢
	8 pm to 10 pm / 20 h à 22 h	Mid-peak / Période moyenne	7.5 ¢
	10 pm to 7 am / 22 h à 7 h	Off-peak / Période creuse	3.5 ¢

Effective August 2006 / Efficace le 2006 août

Exhibit 13: A sample of the fridge magnet provided to all participants

4.3 Incentive Approach

As an incentive to enrol, participants received a "thank you payment" of $75.00 (adjusted, as described in Section 4.4 below) at the end of the pilot. Specifically, $50 was provided as an incentive for remaining on the pilot for the full period and $25 was provided for completing the pilot survey.

Such an incentive is consistent with incentive payments of $75 to $100 made in similar pilots. Numerous researchers have concluded that the incentive does not present an issue when analyzing the effect of prices on pilot participants. The reason is that the incentive payment is a fixed externality; participants receive credit for the $75 simply by participating. Any savings or losses on their time-based pilot prices do not change the fact that they will receive the incentive payment, beyond reducing or increasing it.

4.4 Billing

To accommodate the needs of the pilot, participants continued to receive and pay their "normal" bi-monthly electricity bill from Hydro Ottawa. This bill was issued by Hydro Ottawa every other month at a different time during the month for any given customer.

Separately, pilot participants received monthly *Electricity Usage Statements* that showed their electricity supply charges on their respective pilot price plan. These statements emphasized the amount of electricity consumed (in each pricing period) and the TOU price of electricity (in each period by day). The statements were mailed to participants monthly, and all usage was on a calendar month basis.

Participants did not remit the dollar amounts shown on the electricity usage statements. Instead, at the end of the pilot, participants received a final settlement comparing their electricity charges on the pilot prices with what their charges would have been on the two-tiered RPP prices.

With a final settlement in March 2007, following the end of the pilot, participants received a cheque in an amount equal to the base incentive adjusted by the amount of their savings or losses on TOU pricing. Thus, participants faced actual economic gains or losses based on their response, or lack thereof, to TOU prices.

Given the above, only the incentive payment amount is affected. As such, the pilot has been designed to have no impact on utilities financial systems or the RPP variance account held by the Ontario Power Authority.

4.5 Critical Peaks

4.5.1 Critical Peak Notification

At the time of enrolment, participants indicated their preference for receiving automated notification of critical peak events by phone, e-mail, or text messages (on cell phones). Notifications were delivered on the day before a critical peak event, usually in the afternoon, no later than 5:00 pm.

Some participants asked for two modes of notification. This proved to be helpful when one mode of contact failed. A few participants did not provide any phone or e-mail contact information. Phone numbers were obtained from Hydro Ottawa for all but one of these participants, and those were put on the call list for notification.

We were unable to obtain contact information beyond a mailing address for one participant in the CPR group. This person did not receive any critical peak notifications during the pilot, and was excluded from analysis of the results.

Critical peak notification success rates were typically between 95% and 98% over the pilot period. If an automated phone message was picked up by the receiver, whether it was an answering machine or a live person, the message was considered to be delivered. If an e-mail was not bounced back or otherwise marked as “undeliverable,” it was considered successfully delivered.

Focus group feedback indicated that participants were generally satisfied with the mode of day-ahead e-mail or phone notification they had chosen. Some had to work out their filtering process for unwanted phone calls, but this was not a significant barrier to participating in the critical peak test group.

4.5.2 Summertime Critical Peak Events

During the summer period of the pilot, four critical peak events were called based on day-ahead forecasts that exceeded the thresholds. Actual temperatures on the event days are provided below.

Critical Peak Day	Time Period	Actual Max Temp (°C)	Actual Max Humidex	Time of High Temp	Mean Daily Temp (°C)
Friday, August 18	1:00 - 5:00 pm	30.0	35	4:00 pm	23.5
Tuesday, August 29	2:00 - 5:00 pm	25.2	28	3:00 pm	20.8
Thursday, September 7	2:00 - 5:00 pm	22.4	n/a	4:00 pm	15.7
Friday, September 8	2:00 - 5:00 pm	26.5	31	3:00 pm	19.9

Exhibit 14: Actual temperature and Humidex characteristics of declared summertime critical peak events against a temperature trigger of 28°C and a Humidex of 30°C during On-Peak times

Since the summer was moderate compared to previous summers (the previous five years were analyzed to establish the critical peak dispatch threshold), the events represented situations just slightly over the threshold values, or in some cases the actual temperature was below the day-ahead forecast and the threshold. This is significant because other pilots have found that less load shifting occurs on moderate days in comparison to extreme temperature days.

4.5.3 Wintertime Critical Peak Events

Three critical peak events were called in winter based on a day-ahead forecast of below -14°C during On-Peak hours.

Critical Peak Day	Time Period	Actual Min Temp (°C)	Actual Min Temp (°C) During Peak Period	Mean Daily Temp (°C)
Tuesday, January 16	5:00 – 8:00 pm	-20.5	-18.7	-14.9
Wednesday, January 17	5:00 - 8:00 pm	-25.3	-16.1	-19.8
Friday, January 26	7:00 – 11:00 am	-22.1	-21.3	-20.2

Exhibit 15: Actual temperature characteristics of declared wintertime critical peak events against a temperature trigger of -14°C

During the pilot, seven critical peak events were declared (a total of 23 hours) compared to a maximum of nine events.

4.6 Participant Support

The implementation team provided both telephone and email support for participants. The phone support is staffed from 11:00 am – 8:00 pm Ottawa time. Support was available in both English and French.

Only about a dozen participants used the e-mail support feature of the project to resolve issues related to their participation. These participants had questions regarding metering, critical peak times, and minor changes to their billing information. Where appropriate, inquiries were forwarded to a contact at Hydro Ottawa to be addressed.

The OSPP telephone support line received approximately 235 calls and voice messages. About 150 of the calls were directly related to the OSPP, with most of these were inquiries during the recruitment phase of the project. Around 60 calls were mistaken faxes or wrong numbers, since another organization has mistakenly listed this number as their toll-free number. The remaining 25 calls were not related to the pilot project; they were questions about the participants' regular Hydro Ottawa service or they were calls from non-participants who wanted to know about smart metering in general.

Phone support logs indicate that callers were knowledgeable about and involved in the management of their electricity usage. In about a dozen of the roughly 30 calls which were specifically about the pilot project, logged in the month immediately after the enrolment period, callers articulated to the phone support staff that they were using their participation in the pilot project and their access to smart meter data as a way to gain more control over their relationship with the utility.

5 Demand Response and Conservation Impacts

Impacts on pilot participants were modelled and measured from three perspectives:

- Demand response impacts, or the amount of load shifting away from critical peak or On-Peak hours
- Conservation effects, or the reduction in total electricity consumption, regardless of when (or which TOU period) the electricity is used
- Bill impacts, comparing what participants paid on the TOU prices versus what they would have paid on the two-tiered RPP prices

5.1 Demand Response Impacts

The analysis of demand response or peak shifting as a result of the pilot prices was performed by Professor Frank Wolak of the Economics Department of Stanford University.

The analysis was performed to assess the following:

- Demand response via load shifting away from critical peak hours to either Mid-Peak or Off-Peak hours only on critical peak days
- Demand response via load shifting away from On-Peak hours to either Mid-Peak or Off-Peak hours on all non-holiday weekdays

These effects are determined by comparing the electricity consumption behaviour of customers receiving the experimental prices (TOU, CPP, and CPR) and the behaviour of customers remaining on their existing two-tier RPP prices. These customer groups are the treatment and control groups respectively.

5.1.1 Analytical Model

To analyze the load reductions during peak and critical peak times, a nonparametric conditional mean estimation framework was used. The framework used customer-level fixed effects and day-of-sample fixed effects.

The fixed effects approach uses a separate intercept term for each customer to control for effects that are unique to that customer and relatively constant over the time period being examined. The unique effects of the stable, but unmeasured characteristics of each customer are their “fixed effects” from which this method takes its name. These fixed effects are held constant. The fixed effects nature of the model means the model does not need to include unchanging customer characteristics such as house size, appliances, etc.

Controlling for fixed effects controls the amount of variance (noise) the model is faced with, since each customer has a different base load, a different response to weather, and a different pattern of consumption that changes over time. This approach also provides for a much closer fit to the data than most models, as individual responsiveness is incorporated.

This approach has worked well in estimating the impacts of mass-market programs such as the California Statewide Pricing Pilot, the Idaho Power critical peak pricing pilot, and the Sacramento Municipal Utilities District air conditioning direct load control program.

More details on the model and the full results can be found in Appendix E.

5.1.2 Critical Peak Shifting Results

Exhibit 16 shows the amount of load shifting on individual critical peak days during the summer for all three price groups combined. These results are for the Entire On-Peak Period. Results that are not statistically significant at the 90% level are denoted by "n/s"; however, many of the load shift results are statistically significant at the 95% and even 99% confidence level.[17]

A statistically significant shift in load away from peak periods was measured during On-Peak periods on two critical peak days called in August.

Critical Peak Day (Entire Peak Period)	Summer	Actual Max Temp (°C)	Actual Max Humidex
Friday, August 18	27.7%	30.0	35
Tuesday, August 29	10.1%	25.2	28
Thursday, September 7	n/s	22.4	n/a
Friday, September 8	n/s	26.5	31
	Winter	**Actual Min Temp (°C) During Peak Period**	
Tuesday, January 16	n/s	-18.7	
Wednesday, January 17	-7.2%	-16.1	
Friday, January 26	n/s	-21.3	

Exhibit 16: Shifts in consumption for each of the seven days by all price groups when a critical peak was declared. n/s denotes that the results where not statistically significant.

The only statistically significant load shifting evident by members of the three price groups during the five critical peak days in September or January was an *increase* in

[17] - The statistical precision of each specific result may be determined using the standard error, which is included in Appendix E for each of the results.

load on January 17. This may be a statistical anomaly or the greater difficulty of shifting load during the winter identified during the focus groups.

Given the lower number of data points, results for individual price groups, for individual events are not statistically significant.

Exhibit 17 provides the estimated percentage shift in load across the seven days (four in summer, three in winter) when a critical peak event was called, broken down by season and by participant price group.

"Critical peak period" refers to the fraction of the entire On-Peak period of the day that the critical peak period covers (only three or four hours of the six- or seven-hour On-Peak period on each critical peak day were critical peak hours).

	TOU only	CPP	CPR
Period		**Summer**	
Critical Peak hours (3 or 4 hours during the Peak)	5.7%(n/s)	25.4%	17.5%
Entire On-Peak period	2.4%(n/s)	11.9%	8.5%
Mid-Peak	n/s	n/s	n/s
Off-Peak	n/s	n/s	n/s
		Winter	
Critical Peak periods	n/s	n/s	n/s
Entire On-Peak period	n/s	n/s	n/s
Mid-Peak	n/s	n/s	n/s
Off-Peak	n/s	n/s	n/s
		Total	
Entire On-Peak period	n/s	8.1%	5.2%
Mid-Peak	n/s	n/s	n/s
Off-Peak	n/s	n/s	n/s

Exhibit 17: Shifts in consumption during the seven days (four in summer, three in winter) when a critical peak was declared. n/s denotes that the results were not statistically significant.

Statistically significant results were obtained for CPP and CPR price groups during critical peak and On-Peak periods on the summer critical peak days. The most dramatic was a 27.7% shift in load during the event of August 18.

The percentage reductions shown for the TOU only customers in Exhibit 16 are the actual reductions recorded for that group; had there been more critical peak days, it is likely these results would be statistically significant.[18]

Other outcomes include:

- The average demand reduction across both critical peak groups (25.4% and 17.5% for CPP and CPR respectively) during critical peak hours was 21.5%.
- TOU-only participants did not demonstrate a statistically significant shift in load on critical peak event days. Unlike CPP and CPR participants, these participants were not notified of the event the day before.
- Participants demonstrated a much better ability to shift load in the summer relative to winter.
- No statistically significant load shifting was evident by members of any of the three price groups during the Mid-Peak periods of critical peak days.

5.1.3 Time-of-Use Peak Shifting Results

On days when a critical peak event was not declared, all participants were effectively on the TOU-only price structure. Exhibit 18 shows the results. The only statistically significant load shifting detected on these days was a counterintuitive increase in the on-peak usage of the CPP group.

Price Group	Shifting from On-Peak
TOU Customers	n/s
CPP Customers	-10.8%
CPR Customers	n/s

Exhibit 18: Load shifting on all weekdays, except holidays, during the full pilot period. The result for the CPP customers is counterintuitive.

5.2 Conservation Effect

While a main purpose of time-of-use and critical peak pricing is to reduce peak demand, these programs also typically result in a small reduction in total electricity consumption as well. There are three reasons a small reduction often occurs, even though it is not the primary objective in relation to TOU pricing.

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[18] - The results for the TOU-only participants are relatively consistent with the results of the California Statewide Pricing Pilot which were 5.5% (inner summer) and 2.3% (outer summer) when only On-peak and Off-peak prices applied.

- Higher peak or critical peak prices induce load reductions during peak hours, not all of which is shifted to other times. Some reductions are uses that are shifted to other time periods, such as laundry. In these cases, the usage is “recovered” at other times. In other words, consumption or load has only been “shifted”. Other reductions, such as lower lighting, are not recovered, as there is no reason for it.
- Dynamic pricing programs cause participants to have a higher awareness of how they use electricity, which, in turn, results in lower consumption.
- These programs usually increase the amount of usage information, or feedback, received by the customer, also lowering consumption.

5.2.1 Analytical Model

The basic methodology for assessing the conservation effect was the same as that used for load shifting. Again, a nonparametric conditional mean estimation framework was used.

A key difference from the load shifting analysis is that the conservation analysis utilized billing period data from the previous year for pilot customers. The reason is that too little of the necessary data was available from smart meters, because the conservation analysis requires comparing the usage of the control and treatment groups before and after being placed on the pilot prices.

Specifically, the analysis compares the usage of the two groups (technically four, since the treatment customers were on three different price plans) before the pilot, then after going on the pilot. By comparing the differences between the groups for the pre-experimental period with the experimental period, the conservation effect is revealed. For example, if the treatment group used 2% less than the control group during the same period last year, but 5% less during the pilot period, the conservation effect is calculated as 3%.

Adjustments for weather and other externalities are not required as the analysis is comparing total usage of the control and treatment groups for the same period during the previous year and during the pilot period.

5.2.2 Conservation Effect Results

Exhibit 19 provides an estimate of the total reduction in electricity consumption caused by a customer’s being on the pricing pilot.

The average is overall reduction in electricity use across price groups is 6.0%.

These results show conservation was 6.0%, 4.7%, and 7.4% for TOU, CPP, and CPR customers, respectively. All of the results are statistically significant.

Price Group	Percent reduction in total electricity use
TOU	6.0%
CPP	4.7%(n/s)[19]
CPR	7.4%
Average	**6.0%**

Exhibit 19: Conservation Effect (total usage reduction) for the full pilot period

Average Electricity Usage

We calculated the average electricity usage of the three price groups during the pilot period. Exhibits 20 and 21 summarize the results. The higher consumption of the control group relative to the three price groups is consistent with the finding of the load impact analysis that participation in the pilot produced a conservation effect.

Average	TOU	CPP	CPR	Total	Control Group
Average Monthly Electricity Usage (kWh)	683	723	774	727	810

Exhibit 20: Average monthly usage by price group and control group during the pilot period.

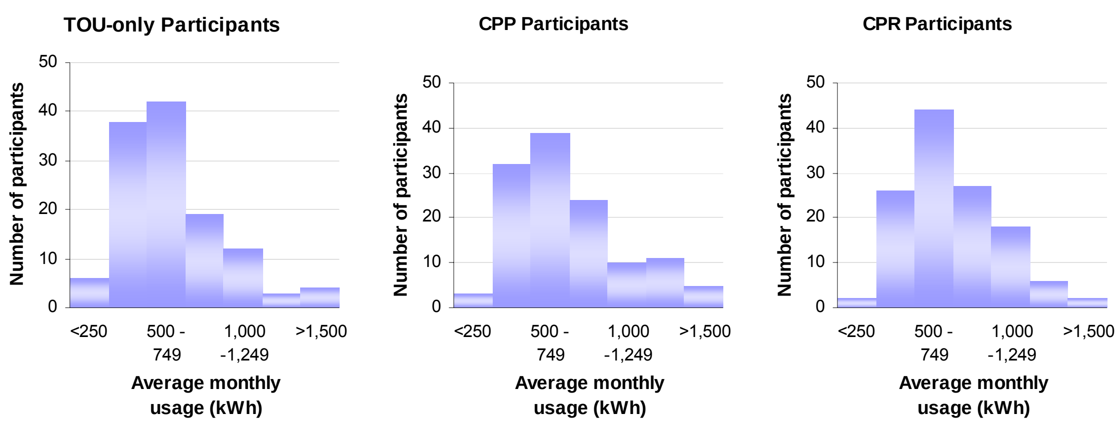


Exhibit 21: Distribution of average monthly usage by price group during the pilot period

[19] - This result is not statistically significant at the 90% confidence level but is included here because it is significant at a confidence level of 88%, or just less than 90%.

5.3 Customer Bill Impacts

5.3.1 Quantifying Load Shift Bill Impacts

This element of the evaluation compares what consumers on the pilot price plans paid for their electricity commodity charge relative to what they would have paid had they remained on the two-tiered RPP prices.

For the pilot, the three price structures were designed to be as revenue neutral as possible relative to each other and the tiered RPP prices. "Revenue neutral" was defined such that a participant whose electricity usage is distributed across the hours in the same way as the provincial average for all RPP consumers would pay approximately the same bill on all three options (and the tiered RPP prices) in the absence of any change in usage.

Given the above, any change in the timing of electricity use caused a change in the bill. The change in the bill was calculated by determining the bill amount each month for each participant for two pricing plans: TOU prices (TOU, CPP, or CPR) and two-tiered RPP prices.

Both the RPP TOU and two-tiered RPP bill amounts were calculated using the hourly electricity usage information collected via the smart meters. Thus, for this portion of the bill impact analysis, it was assumed that the TOU prices had zero effect on total electricity use.

Based on the above, the analysis below addresses five key questions:

- How many participants saved money on TOU prices, and how many paid more compared to the existing two-tiered RPP prices?
- What was the average savings?
- What were the extremes, the greatest individual participant savings and the greatest individual loss?
- What were the differences by price group?
- What were the monthly variations; particularly how extreme could the difference for one month be for an individual participant?

5.3.2 Entire Pilot Period Load Shift Bill Impacts

Exhibit 22 and Exhibit 23 summarize the total impacts on bills from load shift across the entire seven months of the pilot – August 1, 2006 through February 28, 2007.

The pilot prices were designed with the intent to be revenue neutral for CPP participants. The summertime Off-Peak price was reduced from 3.5 to 3.1 ¢/kWh to compensate for the higher CPP price, based on an assumption of *nine* critical peak events. However, due to the moderate weather, only *seven* critical peak events could be called. If this was known upfront, it suggests the Off-Peak price should have been reduced by only 0.3 ¢/kWh. As a result, the savings for the CPP participants are somewhat overstated.

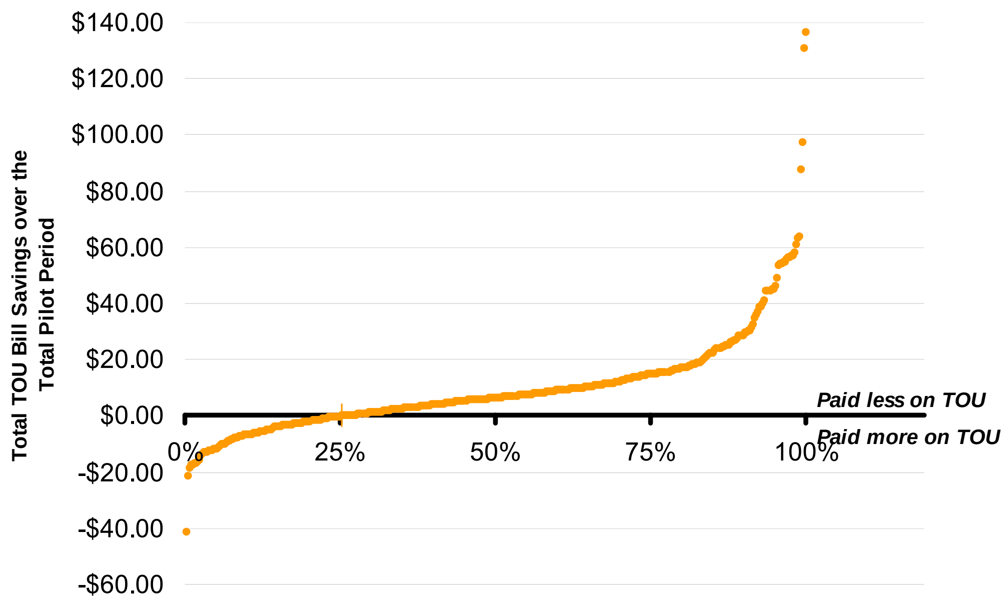


Exhibit 22: Distribution of participant bills savings on TOU prices for the total pilot period. Each dot represents an individual participant's net loss or savings. Those above the line paid less on TOU prices.

Total Pilot Period Difference (Tiered-TOU)	TOU only	CPP	CPR	All
Average	+$5.46	+$12.68	+$12.22	+$10.13
Minimum	-$41.37	-$21.14	-$16.67	-$41.37
Maximum	+$63.49	+$61.28	+$136.64	+$136.64
Average	1.8%	4.2%	2.9%	3.0%
Minimum	-12.3%	-7.6%	-9.1%	-12.3%
Maximum	+13.9%	+13.8%	+10.7%	+13.9%
% of Participants Saving on TOU	64%	83%	77%	75%

Exhibit 23: Distribution of participant bills savings on TOU prices for total pilot period. In the table, a "+" sign equals a savings or a lower bill on TOU/CPP/CPR.

Key observations include:

- Participants, on average, paid lower bills on the TOU pilot prices than they would have on tiered RPP price, with 75% of participants paying less on the TOU prices.
- The average total savings was $10.13, or $1.44 on average per month.

- The greatest individual *savings* was $136.64, (although this was an extreme individual result, the 95th percentile was $46.90, or an average of $6.70 per month).
- The greatest individual *cost* was $41.37 (similarly, the 5th percentile was much less extreme at $11.30, or an average of $1.61 per month).

As expected given their lower average usage (see Exhibit 20), TOU-only participants had the lowest average savings. Lower consumption results in a lower average price on the two-tier prices which in turn results in lower savings relative to charges on the TOU price plans. This effect is greater than any difference in load shifting behaviours between the groups.

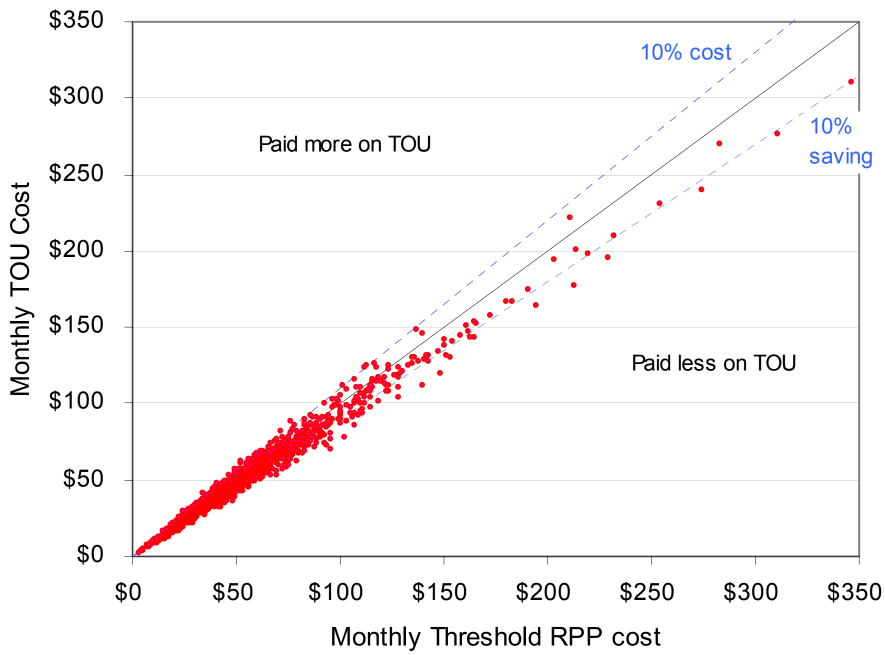


Exhibit 24: Distribution of total monthly statement amounts on one of the TOU prices vs. two-tiered RPP threshold prices

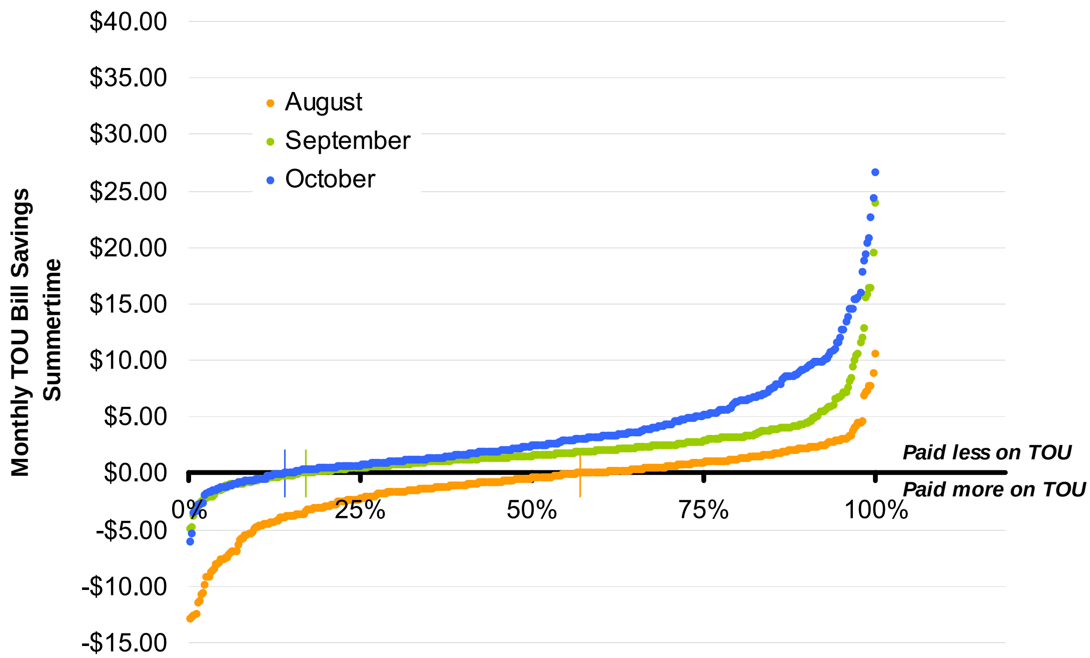
5.3.3 Individual Month Impacts from Load Shifting

Monthly comparisons between TOU and the two-tiered RPP threshold prices are problematic. The RPP threshold prices are designed from a year-long perspective, taking into consideration expected higher usage in summer and winter months, and lower usage in spring and fall months. The RPP seasonal tier threshold changes from 600 kWh to 1,000 kWh per month in November. Under this price structure, consumers who use more than the threshold level of usage pay a higher average price in the summer than the winter. Over the full pilot, such threshold effects are offset when looking at the total bill impacts.

Monthly comparisons are provided in this report to understand the implications for participant's making individual bill comparisons.

Exhibit 25 and Exhibit 26 summarize the same information, but by individual month. Results by individual month were generally consistent with the total. Key observations include:

- As expected, savings were generally greater in the "shoulder months"; September through to a mild December. More than 80% of customers paid less than the threshold RPP prices during these months, and no one paid an increase of more than $7.00 in a month during these four months.
- Savings of up to $35.55 in an individual month were experienced by participants. These savings were extreme. The 95th percentile over all months was $8.84, meaning only 130 of the approximately 2,625 statements issued had savings greater than $8.84.
- Not unexpectedly, August was the only month that the average savings across all three price groups was below zero. August was the month when a participant experienced the largest increase for an individual monthly bill compared to the tiered RPP price ($12.81 for a TOU-only participant). The highest individual increase in any other month was $8.28 in February, whereas in August, 14 customers' costs increased that much.
- Results in January, when three critical peak events were declared, are also as to be expected. Participants paying CPP prices paid the most (average of -$1.29), TOU participants were nearly neutral (+$0.58), and CPR participants saved the most (+$1.63).
- The average savings for all three price groups was greater than zero for every month, except three instances:
  - TOU and CPP customers paid more on average in August (with two critical peak events)
  - CPP customers paid more on average in January (with three critical peak events)



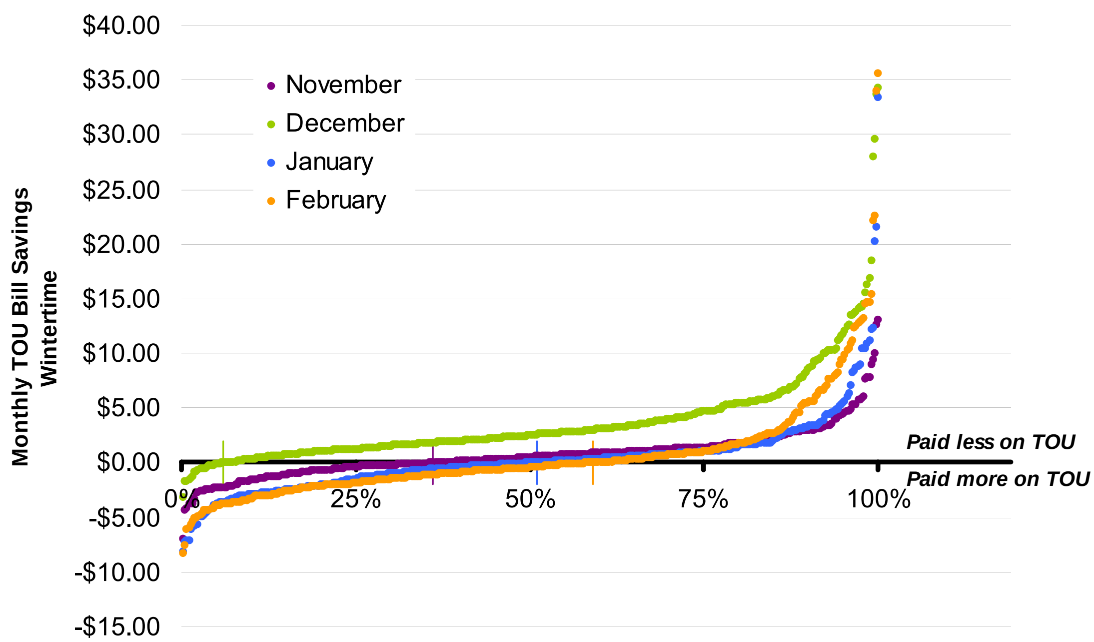


Exhibit 25: TOU savings on participant bills during individual months. Each dot represents an individual participant's net loss or savings. Those above the line pay less on TOU prices.

Month	TOU Savings	TOU only	CPP	CPR	All
August	Average	-$1.71	-$1.49	$0.42	-$0.94
	Minimum	-$12.81	-$12.79	-$7.84	-$12.81
	Maximum	$4.01	$4.60	$10.52	$10.52
	% of Participants on TOU	40%	34%	54%	43%
September	Average	$1.26	$2.45	$2.63	$2.11
	Minimum	-$4.95	-$2.96	-$4.76	-$4.95
	Maximum	$12.91	$15.81	$23.90	$23.90
	% of Participants on TOU	76%	93%	81%	83%
October	Average	$1.85	$6.61	$2.36	$3.62
	Minimum	-$5.31	-$0.81	-$6.06	-$6.06
	Maximum	$17.77	$26.58	$20.81	$26.58
	% of Participants on TOU	78%	100%	82%	86%
November	Average	$0.39	$1.24	$0.61	$0.75
	Minimum	-$4.36	-$6.89	-$3.73	-$6.89
	Maximum	$9.46	$10.03	$13.11	$13.11
	% of Participants on TOU	60%	78%	55%	64%
December	Average	$3.01	$4.28	$4.03	$3.77
	Minimum	-$3.08	-$1.76	-$1.68	-$3.08
	Maximum	$18.48	$16.32	$34.29	$34.29
	% of Participants on TOU	95%	96%	92%	94%
January	Average	$0.60	-$1.29	$1.64	$0.32
	Minimum	-$4.86	-$8.15	-$5.74	-$8.15
	Maximum	$12.41	$7.14	$33.35	$33.35
	% of Participants on TOU	55%	22%	70%	50%
February	Average	$0.08	$1.07	$0.61	$0.59
	Minimum	-$8.28	-$5.63	-$7.48	-$8.28
	Maximum	$15.46	$22.22	$35.55	$35.55
	% of Participants	38%	52%	33%	41%
All Months	Average	$0.79	$1.85	$1.76	$1.44
	Minimum	-$12.81	-$12.79	-$7.84	-$12.81
	Maximum	$18.48	$26.58	$35.55	$35.55

Exhibit 26: TOU savings on participant bills during individual months. A "+" sign equals a lower bill on TOU/CPP/CPR.

5.3.4 Bill Impacts from Conservation

The above analysis on bill impacts considers only the load shifting aspects of TOU prices; conservation effects are not included. In other words, it mimics the results of what a shadow bill program would portray to consumers, where consumers would receive two statements—one based on threshold prices, the other based on TOU prices—*for the same amount of consumption*.

As described in Section 5.2, however, TOU prices have a conservation effect that lowers the overall consumption.

Here, we are limited to applying averages. Assuming a 6.0% conservation effect alone, and based on the average RPP price of about 6.3¢/kWh during the summer months and the lower-tier RPP price of 5.5¢/kWh for the winter months, the savings would range from a few cents for the lowest volume user to over $6 per month for the largest user. Average monthly use for pilot participants was 727 kWh after conserving 6%. Thus the conservation effect at an average price of about 5.9¢/kWh resulted in savings averaging $2.73 per month.[20]

Therefore, on average, participants experienced a monthly savings from both load shifting and conservation on the TOU prices as compared to the two-tiered threshold prices is $4.17.

Savings Source	TOU Bill Savings
Load Shifting	$1.44
Conservation	$2.73
Total Average Monthly Bill Savings During the Pilot Period	$4.17

Exhibit 27: The average monthly TOU bill savings from both load shifting and conservation effects was $4.17.

With this conservation effect considered, 93% of customers would pay less on RPP TOU prices over the course of the pilot, than they would have on RPP threshold prices (compared to 75% without conservation being considered).

[20] - The average RPP price was not used for the winter months because the usage of participants in the pilot was below the winter threshold of 1000 kWh. As a result, the lower RPP tiered price was used to provide a more accurate estimate of the savings due to conservation.

6 Participant Feedback

6.1 Approach

Two formal means of gathering participant feedback were used: focus groups with representatives from each pricing group and a survey targeted at all participants.

6.1.1 Focus Groups

Three focus groups were conducted in Ottawa during the second week of October; one group each for CPP, CPR, and TOU participants. There were 44 participants involved. The focus groups were scheduled so that participants would have had sufficient experience with the program to speak knowledgeably, yet there would be enough time to make minor changes in the pilot if warranted by the feedback.

The focus groups provided the OEB with participant feedback on the following items:

- Why participants chose to participate in the pilot
- How did participants feel about various elements of the recruitment process
- How did participants like the monthly electricity usage statements and what did participants value the most (i.e., if one item could be included in their regular bill)
- Where relevant, participant responses to the information on the critical peak events
- What actions they took and their understanding of the rationale for TOU pricing

More detail on the focus groups is provided in Appendix F.

6.1.2 Participant Survey

As part of this study, IBM’s National Survey Centre conducted a survey of the program participants. A dual methodology was implemented for the survey:

- Invitations to participate in an online survey were sent to all participants on November 22, 2006 who had provided an email address as part of the study.
- The mail survey was distributed by regular mail on November 23, 2006 to all participants who did not provide email addresses as part of the study. The mail surveys also contained unique links to the online survey to encourage participants to complete it online.

A total of 298 surveys were returned by the survey cut-off date of December 14, 2006, for an overall response rate of 79%. The margin of error (at 95% confidence) for the overall results is ± 5.7% for the 298 surveys received.

The margin of error for the different sub-groups presented throughout the report varies depending on the sample size (See Exhibit 28).

Price Group	Responses	Margin of Error
TOU only	94	±10.2%
CPP	103	± 9.7%
CPR	101	± 9.8%
Total	**298**	**± 5.7%**

Exhibit 28: Margin of error by pricing group

As a reference, ± 10% margin of error indicates a difference of at least 20 percentage points is needed to prove a statistically conclusive result.

The complete survey results are provided in Appendix G.

6.2 Rationale for Participating

The top reasons given by focus group participants in all three treatment groups for participating in the pilot were:

- They knew TOU pricing was coming in the near future and wanted to be prepared by seeing how they would fare economically under the TOU price plan
- They liked the idea of being able to monitor their own electricity usage with the tools provided by the project
- They perceived that the design of the TOU pricing and the feedback on their usage would give them more control over their electricity bill

Only a handful of focus group participants indicated that receiving a $75 incentive payment was one of the top three motivations to enrol in the project.

6.3 Communications Feedback

6.3.1 Letters and Fact Sheets

The focus group results indicated that the initial participant education (e.g. recruitment letter, fact sheets, enrolment confirmations, magnets, and electricity conservation brochures) were clear and understandable. In some cases, participants who scrutinized the educational materials overcame initial scepticism towards the project and came to understand that TOU prices were beneficial to consumers and not a “money grab”.

6.3.2 Refrigerator Magnet

The discussion in the focus groups regarding the magnet underscored two things:

- The importance of presenting TOU prices and periods in a clear and concise format, because virtually all participants found the prices understandable “because of the magnet”

- The importance of producing this information in a durable and reproducible form, such as a magnet, because consumers refer to the information frequently and in multiple places as they are adjusting to the TOU prices.

Participants used the refrigerator magnet frequently and provided the most feedback on this educational tool. They reported that it was easy to explain the TOU prices or the pilot project's intent to their friends and neighbours, and to understand it themselves, by referring to the magnet.

They also manage their own electricity usage in response to the prices by referring to the magnet at various times and in various places. They often duplicated the information on the magnet to post in their kitchens, laundry rooms, and near their thermostats, where they would be making decisions about running major appliances such as dishwashers, laundry machines, and air conditioners.

The survey results reinforced the importance of the magnet and on the format used. Participants prefer (61%) the tabular format for displaying the different time periods and associated time-of-use prices over a more graphical approach.

All participants were provided with a replacement fridge magnet before the price change in November. (If it continues to include actual prices, a requirement for keeping the magnet up to date should be noted before any larger distributions are undertaken.)

6.3.3 Conservation Brochure

Because most participants understood the primary purpose of this project was to encourage load shifting, the conservation brochure was not as salient an educational tool. However, many would characterize their participation in the pilot as including an awareness of conservation as well as peak load shifting, and they referred to the brochure to find out how to lower their consumption in general ways at all times, which they saw as contributing to their successful peak load reduction

6.3.4 Statement Provision

Focus group participants and survey results were generally complimentary of the frequency of the usage statements, the colors and presentation of their daily usage graphs, and that the statements seemed more personal or informative than their regular utility bill. In fact, 93% of 282 survey respondents agreed (strongly or otherwise) that the information on the statements was helpful in understanding how much electricity was used during different periods.

The most important aspect of the statements to focus group participants was the daily consumption breakdown by TOU price. Participants identified this as the priority item that should be added to their "normal" electricity bill from their utility, in any future mandatory TOU pricing regime.

The statements were provided monthly, in contrast to the bi-monthly bills Hydro Ottawa customers currently receive. There was a consensus among focus group participants that bi-monthly frequency was not adequate within the context of smart meters and TOU pricing.

Online access to energy information was seen by focus group members as less important than informative monthly bills. Nearly 70% of survey responses did indicate that they anticipate accessing an online statement at least monthly. Nearly 11% indicated a desire for accessing information daily.

Frequency of accessing usage statement by internet/e-mail	Responses
Daily	10.6%
Weekly	27.4%
Monthly	31.8%
Less frequently	18.8%
Never	11.3%

Exhibit 29: Survey responses to anticipated frequency of accessing information on electricity usage statement if available by internet or e-mail

In the majority of cases across the three treatment groups, participants understood the information as presented, paying close attention to the times and amount of their electricity usage.

They actively used the information to gauge their hourly consumption and made adjustments in the times of their electricity use. They were well versed enough in the format to be able to look at their daily records and attempt to explain spikes or declines in usage ("I was working from home that week" or, as one phone caller said, "I'm going to see what happens when I fire up my kiln on a weekday").

Focus groups also indicated a strong desire to compare costs under current Two-tiered RPP prices with the RPP TOU prices. They suggested that the Electricity Usage Statements be modified to include their other charges (e.g. distribution and debt recovery) so that they could see what they would really be paying under the TOU prices.

They also suggested that, in order to compare the monthly statement with the regular bi-monthly bill, the statement needed to include a calculation of what they would have actually paid under the tiered prices.

These and other suggestions about format were considered and incorporated where possible by the project implementation team. For instance, subsequent statements provided pilot participants with a comparison of their bills under the TOU and tiered prices. This was the change that most participants felt was most important. The other change was not felt to be as important given that all of the other (non-commodity) charges would not be materially affected or not affected at all.

6.4 Electricity Use Changes and Understanding of TOU Pricing Rationale

Participant feedback, particularly the focus groups, also provided qualitative input regarding actions participants took in response to being in the pilot and having the pilot prices.

Most focus group participants understood that an appropriate response to TOU prices would be to find opportunities to shift more electricity usage to the Off-Peak periods. For a typical participant, this translated into doing their laundry and dishwashing during Off-Peak times, and adjusting their thermostats in advance of critical peak events.

Some participants also implemented some less common measures. For example, prior to the pilot, one participant cleaned his pool from 7-7 during the *day*; after the pilot started, the pool was cleaned from 7-7 during the *night.*

Survey respondents indicated that they were more likely to significantly change how they use electricity during On-Peak and critical peak periods. They indicated that the Mid-Peak price point did not have much of an influence on their electricity usage patterns (which is consistent with the intent).

The typical focus group participant would post the TOU price and schedule table (as printed on their refrigerator magnet and in the enrolment fact sheets) in their kitchen and laundry room to remind them of the best times to do laundry or run their dishwashers.

Many considered these to be easy practices to implement to keep their electricity bills under control. Others were willing to change their behaviour to fit the reality of electricity costs, in the hopes that this would result in lower overall prices in the future.

Most focus group participants began these practices as soon as they enrolled in the pilot. After receiving their first few Electricity Usage Statements and seeing the effect of their usage behaviour on their costs, many participants continued their load shifting practices with little adjustment, although a few later realized that they wanted to compare how they fared on TOU prices with and without shifting their usage, and considered trying a month without shifting to develop their own baseline for consumption.

Some found it difficult to fit load-shifting behaviour in their lifestyles. For example, some families with small children attested to the difficulty of curtailing their laundry activity during Mid-Peak and On-Peak periods. However, it is encouraging to note that even those families that were unable to change their load shape felt they were not penalized under the existing TOU prices. No one felt as if the TOU prices were the “money grab” and “gouging” that many had feared and/or perceived going into the pilot.

Not all participants understood the policy rationale behind managing peak demand, but a few expressed the perception that, regardless of whether the peak demand was attributable to industry or the residential sector, if every consumer did their part to reduce peak load, eventually the system would be more reliable and they could keep electricity prices down as a result. A number of participants also discussed the need to avoid brown-outs and/or black-outs.

6.4.1 Critical Peak Groups

In response to a critical peak notification, customers might reset their thermostats by a few degrees, as suggested by the PowerWise marketing materials provided to the participants, or plan on dining out or cooking on an outdoor grill during a critical peak event. Those participants with timers on their dishwashers and programmable thermostats would experiment with setting their appliances to consume less power during peak times. Some noted that they first used their timers after the pilot started.

The rule of thumb used was that for a critical peak event, only the essential “non-negotiable” appliances (such as refrigerators) would continue to run. However, for the most part, focus group respondents felt that they had already pared back their electricity consumption to the minimum in response to the On-Peak price, and that there was no more shifting they could accomplish in response to CPP or CPR during a critical peak period.

6.4.2 Expected Bill Impact

The impact on individual bills seemed to be less than many focus group participants had hoped. Very few of the focus group participants realized what they would consider “large” savings on their electricity bills, and in fact many focus group participants expressed disappointment that their efforts did not result in greater savings. Some considered that it was not worth the extra effort to do laundry late at night or on weekends for such small bill savings, while some stated that their primary motivation was electricity conservation and that the small savings were not a concern.

These bill comparisons by participants are complicated by many factors:

- Comparisons of pilot Electricity Usage Statements calculated for each calendar month against bi-monthly bills from Hydro Ottawa calculated from various billing dates
- Comparisons of electricity commodity changes alone against a Hydro Ottawa bill that includes distribution and other charges

- Comparisons between pricing structures that are designed to be revenue neutral for an entire year, but have different effects on individual months (As described above in the description of monthly bill impacts)
- Finally, comparisons that do not consider the bill reductions resulting from the average conservation effect realized by participants on TOU prices.

6.5 General Program Satisfaction

6.5.1 Main Benefits of the Program

Based on survey results, being more aware of how to reduce their bill and knowing when electricity is being used are clearly the top benefits of the time-of-use pricing plan. Being more conscious of peak usage is also a main benefit according to pilot participants.

	Total	CPP	CPR	TOU
More aware of how to reduce bill	100.0%	100.0%	100.0%	100.0%
More aware of when electricity is used	90.6%	94.7%	93.2%	84.2%
More conscious of peak usage	85.6%	87.2%	82.5%	87.1%
Gives greater control over costs	67.1%	59.6%	75.7%	65.3%
More aware of total consumption	56.4%	58.5%	49.5%	61.4%
Benefits the environment	52.3%	50.0%	53.4%	53.5%
Other benefits	1.3%	2.1%	1.0%	1.0%
No benefits	0.7%	1.1%		1.0%
Total	100.0% (n=298)	31.5% (n=94)	34.6% (n=103)	33.9% (n=101)

Exhibit 30: Responses to "What is the MAIN benefit the time-of-use pricing plan offers to its customers?" Note that column percentages may add to more than 100% due to multiple responses.

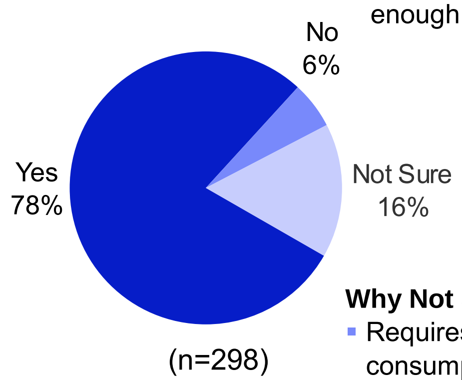
6.5.2 Program Satisfaction

The majority (78%) of survey respondents would recommend the time-of-use pricing plan to their friends, while only 6% would definitely not.

Respondents most frequently cited more awareness of how to reduce their bill, giving greater control over their electricity costs and environmental benefits as the top three reasons behind recommending time-of-use pricing. (See Exhibit 31 for further reasons why and why not.)

These results are consistent regardless of which pricing plan the participants were enrolled in for the pilot.

Why Not?
- Requires too much effort to reduce consumption (n=7)
- Potential savings are not great enough (n=6)



Why Not Sure?
- Requires too much effort to reduce consumption (n=10)
- Unsure if the time-of-use pricing plan is actually beneficial (n=8)
- Potential savings are not great enough (n=5)
- Information provided is either too complicated or insufficient (n=4)
- Plan is only beneficial if you have a flexible schedule (n=3)

Why?
- More aware of how to reduce bill (n=53)
- Gives greater control over costs (n=45)
- Benefits the environment (n=32)
- More conscious of peak usage (n=24)
- More aware of when electricity is used (n=15)
- Increases awareness (n=12)
- Reduces consumption (n=9)
- More beneficial (n=6)
- Prepares consumers for future implementation of smart meters (n=6)
- Increases consumers' responsibility (n=2)

Exhibit 31: Would you recommend the time-of-use pricing plan to your friends if the pilot project was expanded? Why or why not?

6.6 Pricing Structures Preferences and Understanding

6.6.1 Pricing Structure Preferences

Based on survey responses, the majority of participants (74%) preferred TOU-only pricing out of the four options. This was consistent regardless of which pricing plan in which they were enrolled.

While interest in the CPP and CPR plans was only moderate, less than 20% prefer the existing two-tier pricing used by Hydro Ottawa before the pilot. Most would not want to go back to two-tier pricing. (See Exhibit 32).

Notably, participants enrolled in the TOU-only pricing plan were significantly less likely to indicate that the CPP plan was of most interest to them.

Note that participants were provided with a one-sentence description of the pricing plans and most likely had no experience with any plans other than the one they were on for the pilot.

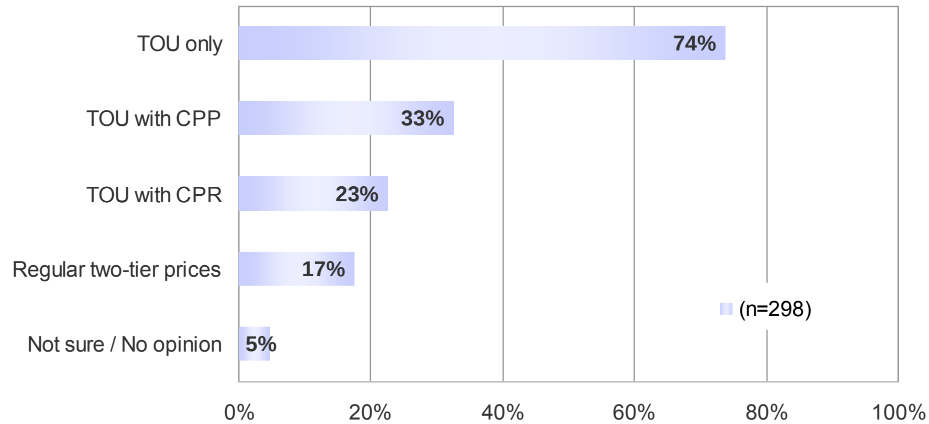


Exhibit 32: Three-quarters of participants preferred TOU-only pricing over the other options, including the current tiered pricing.

Other notable results include:

- Participants enrolled in the TOU-only price plan were significantly less likely to indicate that the CPP or CPR plans were of *most* interest to them (only 19%).
- 42% of CPP participants chose CPP as the *most* interesting to them. While 36% of CPR chose the CPR plan.

6.6.2 Pricing Structure Recall

We tested the recall abilities of participants during the survey. Participants were instructed to not refer to their fridge magnets or other materials.

This survey was completed after only less than four months on the new TOU prices and within one month after a change to the TOU periods from the summer to the winter periods.

The following were the results:

- 38% of survey respondents were able to correctly identify that the price changed four times during a summer weekday.
- 30% of survey respondents were able to correctly identify that the price changed five times during a winter weekday.

In regard to the start time of the On-Peak and Off-Peak periods:

- 35% of survey respondents could correctly identify 11:00 AM as the start of the summertime On-Peak period.

- Another 25% confused the start of the Mid-Peak with the start of the On-Peak period. They thought the On-Peak started at 7:00 AM. That is actually the start of the summertime Mid-Peak period.
- Other responses were spread evenly from 5:00 AM to as late as 5:00 PM

Respondents were better able to recall the end of the On-Peak period:

- Over half of the survey respondents correctly identified 5:00 PM as the end of the summertime On-Peak period.
- Responses from remaining participants ranged from 10:00 PM to 7:00 PM.

After being one month into the winter period when surveyed, participants were more likely to correctly identify the start and end times of the wintertime On-Peak periods than summertime:

- 47% correctly identified the start and end of the morning peak
- 40% correctly identified the start and end of the evening peak.

All of these results are consistent regardless of the plan in which participants were enrolled.

6.6.3 Pricing Structure Feedback

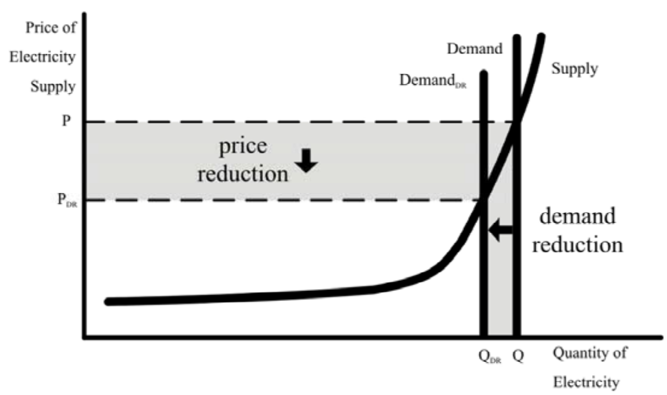
The consensus feedback among focus group participants was that TOU pricing structure was easy to understand and did not need to change:

- When asked if they would prefer only two TOU periods (off- and on-peak, without mid-peak), none of the focus group participants said they desired a change to a two-period structure from the current three-period structure
- For the most part (71%), survey respondents felt that the difference in price points was large enough to encourage them to shift their electricity consumption.
- While all except one focus group participant considered these TOU prices relatively easy to understand, the one participant who would not have characterized the prices as "easy" wanted to acknowledge an added layer of complexity in that there were seasonal changes in the schedule of on-, mid- and off-peak periods; and that winter TOU prices would be more difficult with two on-peak periods each weekday. At the same time, he did not consider this too difficult to understand.

EXCERPT FROM:

BENEFITS OF DEMAND RESPONSE IN ELECTRICITY MARKETS AND RECOMMENDATIONS FOR ACHIEVING THEM

A REPORT TO THE UNITED STATES CONGRESS



Excerpt made by the IEA DSM-Programme with the permission of the US Department of Energy. The full report is available for downloading on
http://www.electricity.doe.gov/documents/congress_1252d.pdf

EXECUTIVE SUMMARY

Sections 1252(e) and (f) of the U.S. Energy Policy Act of 2005 (EPACT)[1] state that it is the policy of the United States to encourage "time-based pricing and other forms of demand response" and encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public. The law also requires the U.S. Department of Energy (DOE) to provide a report to Congress, not later than 180 days after its enactment, which "identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007" (EPACT, Sec. 1252(d)).

Background

Most electricity customers see electricity rates that are based on average electricity costs and bear little relation to the true production costs of electricity as they vary over time. Demand response is a tariff or program established to motivate changes in electric use by end-use customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized.

- *Price-based demand response* such as real-time pricing (RTP), critical-peak pricing (CPP) and time-of-use (TOU) tariffs, give customers time-varying rates that reflect the value and cost of electricity in different time periods. Armed with this information, customers tend to use less electricity at times when electricity prices are high.
- *Incentive-based demand response programs* pay participating customers to reduce their loads at times requested by the program sponsor, triggered either by a grid reliability problem or high electricity prices.

Limited demand response capability exists in the U.S. today.[2] Total demand response and load management capability has fallen by about one-third since 1996 due to diminished utility support and investment.

States should consider aggressive implementation of price-based demand response for retail customers as a high priority, as suggested by EPACT. Flat, average-cost retail rates that do not reflect the actual costs to supply power lead to inefficient capital investment in new generation, transmission and distribution infrastructure and higher electric bills for customers. Price-based demand response cannot be achieved immediately for all customers. Conventional metering and billing systems for most customers are not adequate for charging time-varying rates and most customers are not used to making electricity decisions on a daily or hourly basis. The transformation to time-varying retail rates will not happen quickly. Consequently, fostering demand response through

[1] Public Law 109-58, August 8, 2005.
[2] In 2004 potential demand response capability equaled about 20,500 megawatts (MW), 3% of total U.S. peak demand, while actual delivered peak demand reduction was about 9,000 MW (1.3% of peak).

incentive-based programs will help improve efficiency and reliability while price-based demand response grows.

The Benefits of Demand Response

The most important benefit of demand response is improved resource-efficiency of electricity production due to closer alignment between customers' electricity prices and the value they place on electricity. This increased efficiency creates a variety of benefits, which fall into four groups:

- *Participant financial benefits* are the bill savings and incentive payments earned by customers that adjust their electricity demand in response to time-varying electricity rates or incentive-based programs.
- *Market-wide financial benefits* are the lower wholesale market prices that result because demand response averts the need to use the most costly-to-run power plants during periods of otherwise high demand, driving production costs and prices down for all wholesale electricity purchasers. Over the longer term, sustained demand response lowers aggregate system capacity requirements, allowing load-serving entities (utilities and other retail suppliers) to purchase or build less new capacity. Eventually these savings may be passed onto most retail customers as bill savings.
- *Reliability benefits* are the operational security and adequacy savings that result because demand response lowers the likelihood and consequences of forced outages that impose financial costs and inconvenience on customers.
- *Market performance benefits* refer to demand response's value in mitigating suppliers' ability to exercise market power by raising power prices significantly above production costs.

Quantifying the National Benefits of Demand Response

(Omitted from excerpt)

Recommendations

EPACT directs DOE to recommend how more demand response can be put in place by January 1, 2007. DOE concludes that eleven months is too short a time for meaningful recommendations to be implemented and have any practical impact. Instead, DOE offers recommendations to encourage demand response nation-wide, which are organized as follows:

- **Fostering Price-Based Demand Response**—by making available time-varying pricing plans that let customers take control of their electricity costs. More efficient pricing of retail electricity service is of the utmost importance.
- **Improving Incentive-Based Demand Response**—to broaden the ways in which load management contributes to the reliable, efficient operation of electric

systems. Incentive-based demand response programs can help improve grid operation, enhance reliability, and achieve cost savings.

- **Strengthening Demand Response Analysis and Valuation**—so that program designers, policymakers and customers can anticipate demand response impacts and benefits. Demand response program managers and overseers need to be able to reliably measure the net benefits of demand response options to ensure that they are both effective at providing needed demand reductions and cost-effective.
- **Integrating Demand Response into Resource Planning**—so that the full impacts of demand response, and the maximum level of benefits, are realized. Such efforts help establish expectations for the short- and long-run value and contributions of demand response, and enable utilities and other stakeholders to compare demand response options with other alternatives.
- **Adopting Enabling Technologies**—to realize the full potential for managing usage on an ongoing basis given innovations in communications, control, and computing. Innovations in monitoring and controlling loads are underway offering an array of new technologies that will enable substantially higher level of demand response in all customer segments.
- **Enhancing Federal Demand Response Actions**—to take advantage of existing channels for disseminating information, providing technical assistance, and expanding opportunities for public-private collaboratives. Enhancing cooperation among those that provide new products and services and those that will use them is paramount.

OVERVIEW: KEY FINDINGS AND RECOMMENDATIONS

(Omitted from excerpt)

TABLE OF CONTENTS IN THE EXCERPT[3]

[3] Excerpt made by the IEA DSM-Programme with the permission of the US Department of Energy. The full report is available for downloading on http://www.electricity.doe.gov/documents/congress_1252d.pdf

SECTION 1. INTRODUCTION

The report is [further] organized as follows:

- Section 2 characterizes and defines demand response options, summarizes the role of demand response in our nation's provision of electricity, and introduces a framework for customer decisions about demand response.
- Section 3 includes a conceptual and qualitative discussion of the benefits of demand response.
- Section 4 provides a comparative review and analysis of ten studies that estimate demand response benefits for specific regions or purposes. DOE also suggests methods and considerations for future state or regional efforts to quantify benefits of demand response.
- Section 5 presents specific recommendations for state, regional and federal agencies, electric utilities and consumers to enhance demand response in varying wholesale and retail market structures.
- There are several technical appendices. Appendix A lists interested parties that provided suggestions to DOE on actions or policies to encourage demand response. Appendix B provides a more in-depth conceptual and qualitative discussion of the benefits of demand response. Appendix C summarizes studies on customer response to time-varying prices and demand response programs (e.g. load impacts). Appendix D provides suggestions and technical discussion on protocols and methods for future state or regional efforts to quantify benefits of demand response.

Table 1-1. Response to EPACT Requirements

EPACT Requirement	**Approach**	**Section of Report**
Identify national benefits of demand response	• Synthesize literature and stakeholder input	Section 3
Quantify national benefits of demand response	• Review empirical studies of demand response benefits, normalize results and report range of estimates • Synthesize literature and stakeholder input to develop recommended methods	Section 4
Make recommendation on achieving specific levels of benefits by January 1, 2007	• Solicit stakeholder input and review literature to develop recommendations for encouraging and eliminating barriers to demand response	Section 5

SECTION 2. DEFINING AND CHARACTERIZING DEMAND RESPONSE

What is Demand Response?

Demand response, defined broadly, refers to participation by retail customers in electricity markets, seeing and responding to prices as they change over time. Any commodity market—oil, gold, wheat or tomatoes—consists of both sellers, or suppliers of the commodity, and buyers, or consumers of the goods. For a variety of reasons, very few consumers of electricity are currently exposed to retail prices that reflect varying wholesale market costs, and thus have no incentive to respond to conditions in electricity markets, with results that are detrimental to all.

Demand response may be defined more definitively as:

> *Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*

From the perspective of the electric system as a whole, the emphasis of demand response is on *reductions* in usage at critical times.[4] Critical times are typically only a few hours per year, when wholesale electricity market prices are at their highest or when reserve margins are low due to contingencies such as generator outages, downed transmission lines, or severe weather conditions.

Demand response may be elicited from customers either through a retail electricity rate that reflects the time-varying nature of electricity costs, or a program—an attempt to induce customers to change their consumption behavior—that provides an incentive to reduce load at critical times. The incentive is unrelated to the normal price paid for electricity (e.g., supplemental) and may involve payments for load reductions, penalties for not reducing load, or both.

Demand response represents the outcome of an action undertaken by an electricity consumer in response to a stimulus and typically involves customer behavioral changes. However, its value to society is derived from its cumulative impacts on the entire electric system. Understanding and reconciling these two perspectives is key to characterizing and valuing demand response as well as recognizing its limitations.

The discussion in this section begins by establishing why demand response is important and classifying options for obtaining it. Information on current U.S. demand response capability is then presented. Next, demand response is characterized from the system perspective, illustrating how it fits into electricity system planning and scheduling.

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[4] Demand response may also result in *increases* in electricity usage during the majority of hours when electricity prices are lower than average. This too results in more efficient use of the electric system and may also promote economic growth.

Finally, demand response is discussed from the customer perspective, focusing on how and why customers make decisions to participate and respond (or not).

Why is Demand Response Important?

> *There is a growing consensus that insufficient levels of demand response exist in the U.S. electric power system.*

In recent years, there has been growing consensus among federal and state policymakers that insufficient levels of demand response exist in the U.S. electric power system (EPACT 2005, FERC 2003, NARUC 2000, GAO 2004 and 2005). Due to its physical properties, electricity is not economically storable at the scale of large power systems. This means that the amount of power plant capacity available at any given moment of time must equal or exceed consumers' demand for it in real time. Electricity also has few substitutes for certain end uses (e.g. refrigeration, lighting). The marginal cost of supplying electricity is extremely variable because demand fluctuates cyclically with time of day and season and can surge due to unpredictable events (e.g., extreme temperatures) and because generation or transmission capacity availability fluctuates (e.g., due to a generation plant outage or transmission line failure).[5] While the cost of electric power varies on very short time scales (e.g., every 15 minutes, hourly), most consumers face retail electricity rates that are fixed for months or years at a time, representing *average* electricity production (and transmission and distribution) costs.

> *The disconnect between short-term electricity production costs and time-averaged, fixed retail rates paid by most consumers leads to an inefficient use of resources.*

This disconnect between short-term marginal electricity production costs and retail rates paid by consumers leads to an inefficient use of resources. Because customers don't see the underlying short-term cost of supplying electricity, they have little or no incentive to adjust their demand to supply-side conditions.[6] Thus, flat electricity prices encourage customers to over-consume—relative to an optimally efficient system in hours when electricity prices are higher than the average rates, and under-consume in hours when the cost of producing electricity is lower than average rates. As a result, electricity costs may be higher than they would otherwise be because high-cost generators must sometimes run to meet the non-price-responsive demands of consumers. The lack of price-responsive demand also gives

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[5] LSEs must secure access to capacity for generation, transmission, and distribution in place before demand occurs, given that electricity can not be stored and must be supplied in real-time to meet geographically dispersed demand. Typically, the most costly generators to operate are only used when demand is at its highest or when other units are temporarily unavailable.

[6] This disconnect between short-term power costs and what retail electricity customers pay may also lead consumers to acquire appliances and pursue applications of electricity that build in long-term inefficiencies and barriers to change.

generators the opportunity to raise prices above competitive levels and exercise "market power" in certain situations.[7]

An important benefit of demand response is avoided need to build power plants to serve heightened demand that occurs in just a few hours per year.

In the long term, the impact of insufficient demand response may be even greater as non-price-responsive peak demand can result in long-term investments in expensive generation capacity. An important benefit of demand response is therefore avoidance of capacity investments in peaking generation units to serve heightened demand that occurs in just a few hours per year.

Demand response also provides short-term reliability benefits as it can offer load relief to resolve system and/or local capacity constraints. During a system emergency or when reserve margins are low, it may be necessary for a utility to ration end user loads to preserve system integrity and/or prevent cascading blackouts. Selectively curtailing service to customers that place lower values on loss of service and voluntarily elect to participate in an emergency demand response program is less expensive, less disruptive and more efficient than random rationing (e.g. curtailing loads via rotating outages).[8] It is also possible for time-varying rates (e.g., RTP) to provide load relief that can help resolve system capacity constraints as customers respond to high on-peak prices.

Many regions are facing significant energy price pressure, demands for substantial grid infrastructure modernization, and concerns regarding excessive reliance on natural gas to fuel electric generation. Improved demand response is critical to improving all of these situations.

Classifying Demand Response Options

There are two basic categories of demand response options: retail pricing tariffs and demand response programs. The specific options for demand response are defined and described in the textbox below.

Time-varying retail tariffs, which include TOU, RTP and CPP rates can be characterized as *"price-based" demand response*. In these tariff options, the price of electricity fluctuates (to varying degrees) in accordance with variations in the underlying costs of electricity production. Time-varying tariffs may be offered as an optional alternative to a

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[7] Excessive market power has been measured in several electricity markets in the U.S. and attributed, among other reasons, to insufficient price-responsive load (Borenstein et al. 2000, ISO-NE 2005a, PJM Interconnection 2005a).

[8] Utilities (and now ISOs/RTOs) have developed several program designs that induce customers to reveal their private values/information on outage costs. One approach, based on demand subscription, allows customers to specify a firm service level (FSL) below which they cannot be curtailed and are priced at a higher rate than applies to any residual load, which is curtailable (Woo 1990, Spulber 1992). The customer agrees to curtail this interruptible load during a system emergency.

Demand Response Options

Policymakers have several tariff and program options for eliciting demand response. The most commonly implemented options are described below.

Tariff Options
("price-based" demand response)

- *Time-of-use (TOU):* a rate with different unit prices for usage during different blocks of time, usually defined for a 24-hour day. TOU rates reflect the average cost of generating and delivering power during those time periods. TOU rates often vary by time of day (e.g., peak vs. off-peak period), and by season and are typically pre-determined for a period of several months or years. Time-of-use rates are in widespread use for large commercial and industrial (C/I) customers and require meters that register cumulative usage during the different time blocks.
- *Real-time pricing (RTP):* a rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. RTP prices are typically known to customers on a day-ahead or hour-ahead basis.
- *Critical Peak Pricing (CPP):* CPP rates include a pre-specified high rate for usage designated by the utility to be a critical peak period. CPP events may be triggered by system contingencies or high prices faced by the utility in procuring power in the wholesale market, depending on the program design. CPP rates may be super-imposed on either a TOU or time-invariant rate and are called on relatively short notice for a limited number of days and/or hours per year. CPP customers typically receive a price discount during non-CPP periods. CPP rates are not yet common, but have been tested in pilots for large and small customers in several states (e.g., Florida, California, and North and South Carolina).

Program Options
("incentive-based" demand response)

- *Direct load control:* a program in which the utility or system operator remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice to address system or local reliability contingencies. Customers often receive a participation payment, usually in the form of an electricity bill credit. A few programs provide customers with the option to override or opt-out of the control action. However, these actions almost always reduce customer incentive payments. Direct load control programs are primarily offered to residential and small commercial customers.
- *Interruptible/curtailable (I/C) service:* programs integrated with the customer tariff that provide a rate discount or bill credit for agreeing to reduce load, typically to a pre-specified firm service level (FSL), during system contingencies. Customers that do not reduce load typically pay penalties in the form of very high electricity prices that come into effect during contingency events or may be removed from the program. Interruptible programs have traditionally been offered only to the largest industrial (or commercial) customers.
- *Demand Bidding/Buyback Programs:* programs that (1) encourage large customers to bid into a wholesale electricity market and offer to provide load reductions at a price at which they are willing to be curtailed, or (2) encourage customers to identify how much load they would be willing to curtail at a utility-posted price. Customers whose load reduction offers are accepted must either reduce load as contracted (or face a penalty).
- *Emergency Demand Response Programs:* programs that provide incentive payments to customers for measured load reductions during reliability-triggered events; emergency demand response programs may or may not levy penalties when enrolled customers do not respond.
- *Capacity Market Programs:* these programs are typically offered to customers that can commit to providing pre-specified load reductions when system contingencies arise. Customers typically receive day-of notice of events. Incentives usually consist of up-front reservation payments, determined by capacity market prices, and additional energy payments for reductions during events (in some programs). Capacity programs typically entail significant penalties for customers that do not respond when called.
- *Ancillary Services Market Programs:* these programs allow customers to bid load curtailments in ISO/RTO markets as operating reserves. If their bids are accepted, they are paid the market price for committing to be on standby. If their load curtailments are needed, they are called by the ISO/RTO, and may be paid the spot market energy price.

regular fixed electricity rate or as the regular, default rate itself.[9] Customers on these rates can reduce their electricity bills if they respond by adjusting the timing of their electricity usage to take advantage of lower-priced periods and/or avoid consuming when prices are higher. Customer response is typically driven by an internal economic decision-making process and any load modifications are entirely voluntary.

Incentive-based demand response programs represent contractual arrangements designed by policymakers, grid operators, load-serving entities (utilities and retail electricity suppliers) to elicit demand reductions from customers at critical times called program "events".[10] These programs give participating customers incentives to reduce load that are separate from, or additional to, those customers' retail electricity rate, which may be fixed (based on average costs) or time-varying. The incentives may be in the form of explicit bill credits or payments for pre-contracted or measured load reductions. Customer enrollment and response are voluntary, although some demand response programs levy penalties on customers that enroll but fail to respond or fulfill contractual commitments when events are declared.[11] In order to determine the magnitude of the demand reductions for which consumers will be paid, demand response programs typically specify a method for establishing customers' baseline energy consumption (or firm service) level against which their demand reductions are measured.

Current U.S. Demand Response Capability

(Omitted from excerpt)

The Role of Demand Response in Electric Power Systems

In assessing the benefits of demand response, it is important for policymakers to be cognizant of the physical infrastructure and operational requirements necessary to construct and reliably operate an electric power system as well as regional differences in market structure and industry organization (see the previous textbox).

In all market structures, the management of electric power systems is largely shaped by two important physical properties of electricity production. First, electricity is not economically storable, and this in turn requires maintaining the supply/demand balance at the system level in real time. Mismatches in supply and demand can threaten the integrity of the electrical grid over extremely large areas within seconds. Second, the electric power industry is very capital intensive. Generation and transmission system investments

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[9] TOU rates are in common use as the default service for large commercial and industrial customers throughout the U.S. RTP has been offered as an optional rate for large customers at 40-50 utilities in the U.S., and has been adopted or is under consideration as the default electricity service for large customers in several states where customers can choose their retail supplier (e.g., New Jersey, Maryland, Pennsylvania, New York).
[10] Events may be in response to high wholesale electricity market prices or contingencies that threaten electric system reliability, which can occur at any time of the year.
[11] These performance-based requirements are intended to increase system operators' confidence that demand reductions will materialize when needed.

are large, complex projects with expected economic lifetimes of several decades that often take many years to develop, site and construct.

These features of electric power systems necessitate management of electricity on a range of timescales, from years (or even decades) for generation and transmission planning and construction, to seconds for balancing power delivery against fluctuations in demand (see Figure 2-1). Decisions are made at several junctures along this timeframe. Generally speaking, the amount of load committed at each juncture declines as the time horizon approaches power delivery. For example, 70-80% of supplied load is often committed through forward energy contracts, months or even years before it is delivered. The amount of power arranged on a day-ahead basis varies, but is typically 10-25% of total requirements. In most cases, less than 5% of supply is committed in the last two hours before its delivery.

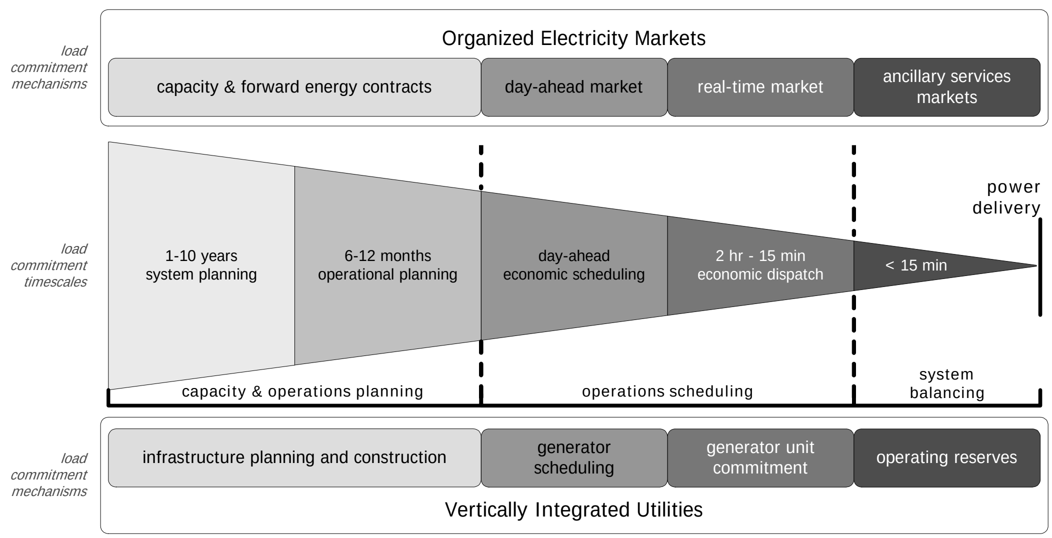

Figure 2-1. Electric System Planning and Scheduling: Timescales and Decision Mechanisms

The major infrastructure planning and operational power delivery decision timeframes are similar in regions with organized wholesale markets and in vertically integrated systems, although the mechanisms for committing energy supply responsibilities differ (see Figure 2-1). In states with retail competition, default service providers and competitive retailers often have a much shorter horizon for acquiring resources than a vertically integrated utility in a state without retail competition.

- *Capacity and operations planning* includes long-term investment and planning decisions. Capacity, or system, planning involves assessing the need for and investing in new generation, transmission and distribution system infrastructure over a multi-year time horizon. Operations planning involves scheduling available resources to meet expected seasonal demand and spans a period of months. In vertically integrated utility systems, these investments are typically evaluated in a utility resource planning process, subject to state regulatory review. In regions with organized wholesale markets, responsibility for these activities is more diffuse. An ISO or RTO engages in a long-term transmission planning process, while distribution utilities retain responsibility for distribution system planning and operations. ISO-administered energy and capacity markets (in some areas) determine the scheduling and operation of available resources to meet daily and seasonal needs and also provide price signals for investments in new generation plants. Utilities and competitive retail suppliers, collectively referred to as load-serving entities (LSEs), contract with generators to meet forward energy requirements.

- *Operations scheduling* refers to the process of determining which generators operate to meet expected near-term demand. This typically involves making day-ahead commitments based on the next day's forecasted demand, with adjustments made in a period of hours down to 15 minutes to account for discrepancies in day-ahead and day-of demand forecasts as well as to account for any unexpected generation plant outages or transmission line problems. Day-ahead and real-time markets administered by ISOs or RTOs fulfill these responsibilities in regions with organized wholesale markets, using generator (or demand resource) offers as the mechanism for scheduling resources for dispatch. Vertically integrated utilities evaluate and schedule generation plants on a merit order basis ranked according to their variable operating costs.
- *System balancing* refers to adjusting resources to meet last-minute fluctuations in power requirements. In regions with organized wholesale markets, resources offer to provide various ancillary services, such as reactive supply and voltage control, frequency-responsive spinning reserves, regulation, and system black-start capability that are necessary to support electrical grid operation.[12] Vertically integrated utilities typically provide ancillary services as part of their integrated operation of the power system.

Ultimately, supply resources are valued according to the timescale of their *commitment* or *dispatch*. Yet because electricity is not storable, its *delivery* to consumers—the goal around which power systems are constructed and managed—occurs in real-time, regardless of when it was committed and priced.

[12] Reserves are a type of ancillary service for which ISO/RTO markets have been established in regions with organized wholesale markets. Generators (and loads) bid their availability to supply backup power with varying degrees of notice (usually from 30 minutes down to 10 minutes). Other types of ancillary services are typically contracted for directly by ISOs or RTOs.

Demand response options can be deployed at all time scales of electricity system management.

Demand response options can be deployed at all timescales of electricity system management (see Figure 2-2) and can be coordinated with the pricing and commitment mechanisms appropriate for the timescale of their commitment or dispatch.[13] For example, demand response programs designed to alert customers of load response opportunities on a day-ahead basis should be coordinated with either a day-ahead market or, in a vertically integrated market structure, with the utility's generator scheduling process. Like generation resources, the actual *delivery* of customer load reductions occurs in real time.

Energy efficiency is a demand-side resource that can be integrated and valued as part of the system planning process and time horizon (Figure 2-2). Though not dispatchable, energy-efficiency measures often create permanent demand-reduction impacts as well as electricity savings.

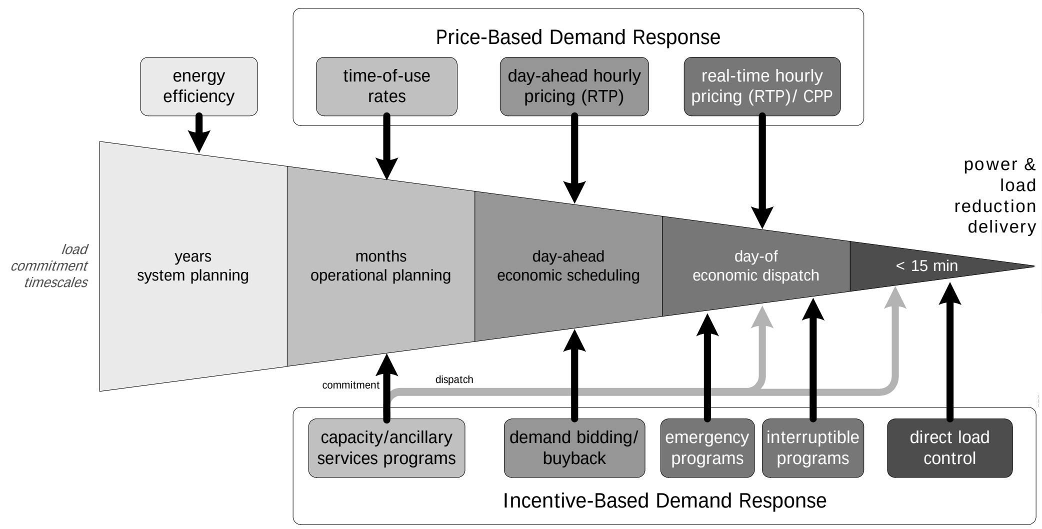

Figure 2-2. Role of Demand Response in Electric System Planning and Operations

If utility resource planners and system operators have a good sense of how their customers respond to changes in the price of electricity, price-based demand response options may be incorporated into system planning at different time scales (Figure 2-2):

- *TOU rates*, which reflect diurnal and seasonal variations in electricity costs but are fixed months in advance, may be valued and integrated as part of operations planning.

[13] In some cases, demand response resources have been included in a Request for Proposals (RFP) process designed to alleviate short-term (e.g., 3-4 years), localized transmission capacity constraints. For example, ISO-NE issued an RFP for demand relief over four years in Southwest Connecticut, where construction of transmission capacity was delayed (Platts 2004), and Bonneville Power Administration issued an RFP for demand reduction, energy efficiency and distributed generation options to defer new transmission investments on a five-year timescale in 1994.

- *RTP* provides hourly prices to customers with day-ahead or near-real-time notice, depending on the tariff design.[14] In wholesale markets with ISOs/RTOs, RTP prices are typically indexed to transparent, location-based, day-ahead or real-time hourly energy market prices; absent an organized spot market, utilities establish RTP "prices" based on the utility's marginal procurement costs.
- *CPP rates* are essentially TOU rates with the addition of a critical peak price that is called on a day-of basis.

Incentive-based demand response programs may be introduced at virtually all timescales of electric system management (Figure 2-2):

- *Capacity programs* involve load reduction commitments made ahead of time (e.g., months), which the system operator has the option to call when needed. The call option is usually exercised with two or less hours of notice, depending on the specific program design. Participants receive up-front capacity payments, linked to capacity market prices, from entities that otherwise would need to purchase comparable levels of generation to satisfy capacity reserve obligations.
- *Ancillary services programs* also involve establishing customer load commitments ahead of time. Customers whose reserve market bids are accepted must then be "on call" to provide load reductions, often with less than an hour's notice.[15]
- Load reductions from *demand buyback* or *bidding programs* are typically scheduled day-ahead, and incentive payments are valued and coordinated with day-ahead energy markets.
- *Emergency programs* are reliability-based, and payments for load reductions are often linked to real-time energy market prices (in regions with organized wholesale markets) or values that reflect customer's outage cost or the value of lost load. Program events are usually declared within 30 minutes to 2 hours of power delivery.
- *DLC programs* are typically reliability-based and can be deployed within minutes because the utility or system operator triggers the reduction directly, without waiting for a customer-induced response.[16]

How Do Customers Accomplish Demand Response?

There are significant challenges in matching customers' preferences for demand response program features to system characteristics that drive value. From the customer

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[14] In some states (e.g., New Jersey, Maryland, Pennsylvania), RTP tariffs have been implemented that are indexed to real-time markets that do not communicate prices until after the fact. No studies assessing observed price response from this tariff design have been conducted. It is conceivable that customers look to near real time prices or day-ahead market prices posted by the PJM Interconnection, as a proxy and adjust their usage accordingly (Barbose et al. 2005).

[15] See Kirby (2003) and Kueck et al. (2001) for more information on customer load participation in ancillary services markets.

[16] DLC can also be used by LSEs to mitigate the impact of high wholesale market prices or manage system-demand related charges.

perspective, investments in demand response and energy efficiency are both DSM strategies that can be used to manage energy costs. Participation in DSM programs (or making DSM investments) involves a series of decisions (see Figure 2-3).

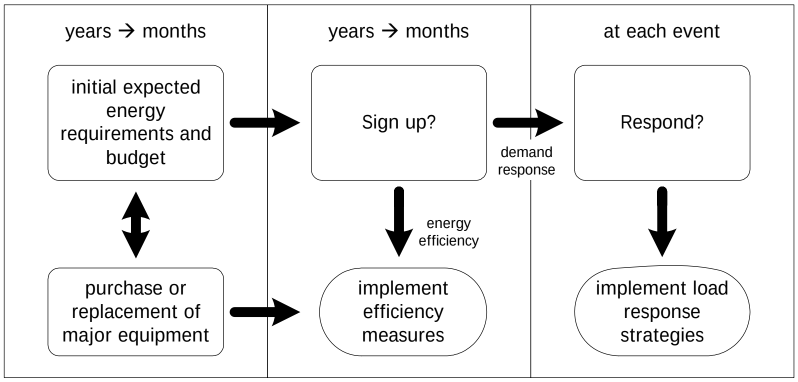

Figure 2-3. Customer Decisions for Demand-Side Management

First, customers implicitly or explicitly determine an initial energy budget based on their expectations of current and future average electricity prices and their household or facility energy needs (see Figure 2-4). The timeframe for this decision (or expectation) is typically monthly or annual, and decisions about purchasing or replacing major energy-using equipment may be made at the same time (see Figure 2-3). The decision-making process may be somewhat different for residential and small commercial customers, who may have a less formalized notion of their usage needs and budget than for large commercial or industrial facilities that may include energy costs as part of a specific operating budget.[17] Larger demand-metered customers are also more likely to be concerned with managing their peak demand in response to demand charges, which are typically included in their electricity tariffs.

Customer participation in demand response options involves *two* important decisions: whether or not to sign up for a voluntary program or tariff (or remain on the option in the case of a default tariff) and, subsequently, whether or not to respond to program events or adjust usage in response to prices as they occur (see Figure 2-3). This is in contrast to traditional energy-efficiency programs, in which customers invest in high-efficiency equipment in response to an existing program offered by a utility, state agency, or public benefits administrator that provides information, technical assistance and/or financial incentives.[18] In most cases energy-efficiency measures, once installed, continue to reduce energy usage over a multi-year economic lifetime, usually without much ongoing customer attention.[19] Compared to the initial usage and budget decision, which is

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[17] This characterization of the customer decision process is more applicable to large, sophisticated, customers. There is a portion of the customer base, particularly many residential and small business customers that have limited understanding of their energy usage patterns and existing tariffs.
[18] Many customers also decide to invest in high efficiency equipment or measures based solely on their own internal economic decision criteria, apart from publicly funded programs.
[19] Some energy-efficient equipment does require ongoing commissioning or maintenance to ensure energy savings continue to be realized over time, or savings may be affected by changes in customer usage of the

relatively simple and familiar to customers, customers' decisions to enroll in demand response programs and to respond during events can be quite complex.

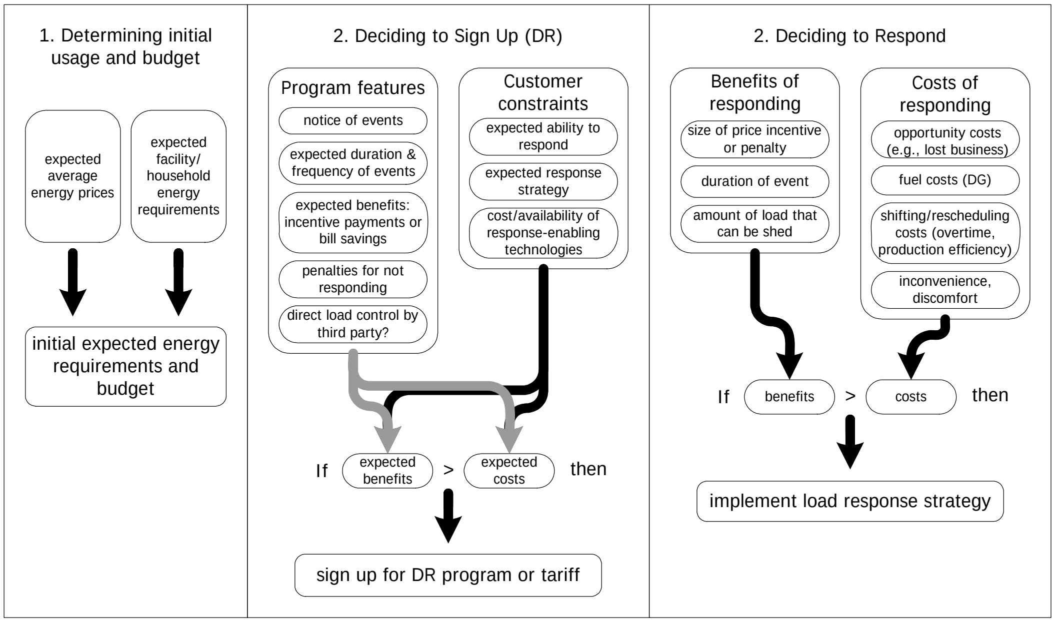

Figure 2-4. Factors Affecting Customer Decisions About Demand Response

The decision to sign up for demand response options involves evaluating offered program or tariff features and weighing the *expected* costs and benefits (see Figure 2-4). A demand response program may specify key parameters of interest to customers (e.g., maximum number of emergency events, payment if event is called), although there is significant uncertainty about the probability and timing of emergency events for the customer.

Ultimately, uncertainties in the costs and benefits of program participation represent risks to customers that may pose significant barriers to their signing up. For example, under RTP, future hourly prices are uncertain, making the benefits of participation difficult to predict.[20]

equipment. Nonetheless, most energy-efficiency investments produce at least some level of savings over a period of years without further customer attention.

[20] However, the most popular form of RTP, two-part RTP, provides some financial protection against unexpectedly high prices, and the primary driver of participation is likely the expectation of *lower* average prices than under a standard tariff. Experience at successful programs (e.g., Georgia Power and Duke Power Company) has shown that some customers reduce load substantially during hours of high prices. Thus, RTP customers have the possibility of achieving bill savings from both lower prices overall, and from responding to high prices when they occur.

The relative certainty of a benefit stream may be as important to customers as the benefits themselves.

Potential participants in emergency demand response programs also face uncertainty about the number of demand response events in which they will be able to achieve benefits, and the payments they will receive when the events occur. Only in capacity-related demand response programs are up-front payments typically provided, in return for which customers agree to curtail on short notice when notified. The relative *certainty* of a benefit stream may be as important as the incentive payments themselves. While certain up-front investments, such as programmable thermostats, energy management systems or onsite generation equipment, may make responding easier, uncertainties about the benefits of responding can make these investment decisions difficult to justify.

Once enrolled, customers must decide whether or not to respond as events arise (see Figure 2-4). The benefits of responding are dependent on the actual financial incentive payment that applies to the given event (including the penalty for not responding), the number of hours that the event extends for, the amount of load the customer can shed, and may also include such considerations as the desire to help others by keeping the electric system secure.[21]

Customers may adopt one or more of three basic load response strategies (see the textbox below) and will assess the actual costs of responding in a specific situation. Their costs of responding depend in part on the type of response strategy undertaken. For example, customers who forego usage without making it up later incur costs due to lost productivity or foregone amenity. Customers that shift or reschedule their energy usage may incur costs from labor rescheduling, overtime pay or productivity losses from adjustments to their production process. If onsite generation is used to respond, fuel and maintenance costs are incurred. For any response strategy, inconvenience or discomfort to building occupants or tenants are likely to be important considerations and may be an important part of the cost-benefit decision, even if they are not directly monetized.

[21] Note that customers in DLC programs often do not have the choice about whether or not to respond during emergency events. Rather, their choices are focused on the decision to enroll or continue to participate in the program.

Types of Customer Load Response

Customers participating in demand response options may respond to high prices or program events in three possible ways:

- *Foregoing:* involves reducing usage at times of high prices or demand response program events without making it up later. For example, a residential customer might turn off lights or turn up the thermostat on an air conditioner during an event, or a commercial facility might turn off office equipment. In both cases, a temporary loss of amenity or comfort results.
- *Shifting:* involves rescheduling usage away from times of high prices or demand response program events to other times. For example, a residential customer might put off running a dishwasher until later in the day, or an industrial facility might reschedule a batch production process to the prior evening hours or the next day. The lost amenity or service is made up either prior to or at a subsequent time.
- *Onsite generation:* some customers may respond by turning on an onsite or backup emergency generator to supply some or all of their electricity needs. Although the customer may have little or no interruption to their electrical usage, their net load and requirements on the power system is reduced.

Load response strategies may be enhanced with technologies and techniques that allow for fully automated demand response. Pilot projects have demonstrated this potential (Piette et al. 2005), although few customers have yet adopted fully automated demand response.

SECTION 3. BENEFITS OF DEMAND RESPONSE

EPACT requires DOE to identify the benefits of demand response in this report. This section addresses this requirement with a conceptual discussion of the various benefits of demand response, how they are derived, to whom they accrue and how to correctly ascribe value to them. The latter is important to policymakers and utilities in determining how much and what types of time-varying rates and demand response programs to include in their resource portfolios.

The following considerations underlie this discussion of demand response benefits:

- *Customers adjust their electricity usage from typical levels in expectation of receiving benefits.* These benefits must be tangible and sufficient to compensate them for the costs they incur to provide demand response, or else they will not respond.
- *Customers and program administrators incur costs in achieving demand response.* Thus, any discussion of benefits must also define and recognize costs, and quantitative assessments should identify net benefits.
- Policymakers should consider the distributional impacts—*who bears the costs and who receives the benefits*—in designing and evaluating demand response strategies.
- *The durability of benefits must be taken into account*; short-term impacts should be distinguished from long-term impacts that provide benefits over a multi-year period.
- There are important *differences in the timing and distribution of demand response benefits* for vertically integrated utilities in states without retail competition compared to regions with organized wholesale markets and retail competition.

This section begins by identifying and discussing the costs of enabling and implementing demand response. Demand response benefits are then discussed, looking at benefits to participants, collateral benefits (which include economic and reliability benefits enjoyed by some or all market participants), and other benefits that are not easily quantifiable. Appendix B provides a more detailed discussion of collateral benefits, including a discussion of differences in the timing and flow of benefits in different market structures.

Demand Response Costs

The costs of realizing demand response can be distinguished as *participant* and *system* costs (see Table 0-1). Individual customers that curtail usage incur participant costs. Demand response program administrators incur system costs to create the infrastructure required to launch and support demand response, including providing incentive payments to customers. System costs may be recovered from ratepayers (either all ratepayers or designated classes of customers) or, in some cases, through “public benefits” charges on their electric bills. Cost recovery decisions are typically made with oversight from state regulatory agencies.

Table 0-1. Costs of Demand Response

Type of Cost		Cost	Responsibility/ Recovery Mechanism
Participant costs	Initial costs	Enabling technology investments	Customer pays; incentives may be available from public benefit or utility demand response programs to offset portion of costs
		Establishing response plan or strategy	Customer pays; technical assistance may be available from public benefits or utility demand response programs
	Event-specific costs	Comfort/inconvenience costs	Customer bears “opportunity costs” of foregone electricity use
		Reduced amenity/lost business	
		Rescheduling costs (e.g., overtime pay)	
		Onsite generator fuel and maintenance costs	
System costs	Initial costs	Metering/communications system upgrades	Level of costs and cost responsibility vary according to the scope of the upgrade (e.g., large customers vs. mass market), the utility business case for advanced metering system or upgrades, and state legislation/policies
		Utility equipment or software costs, billing system upgrades	Utility typically passes cost through to customers in rates
		Customer education	Ratepayers, public benefits funds
	Ongoing program costs[1]	Program administration/management	Costs are incurred by the administering utility, LSE or ISO/RTO and are recovered from ratepayers
		Marketing/recruitment	
		Payments to participating customers	
		Program evaluation	
		Metering/communication[2]	

[1] Ongoing program costs apply for incentive-based demand response programs and optional price-based programs only. For default-service time-varying pricing, ongoing costs are equivalent to any other default-service tariff offering.
[2] Metering/communications costs can include dedicated wire or wireless lines leased from a third-party telecommunications provider and costs to communicate pricing or curtailment information to customers or their energy services suppliers.

Customers undertaking load reductions may incur *initial* as well as *ongoing* costs to respond (see Table 0-1):

- *Initial costs* are incurred before a particular demand response behavior or action can be undertaken. They include devising a load response strategy that takes costs and benefits into account, and investing in enabling technologies to assist with load response. Enabling technologies include devices, such as “smart” thermostats, peak load controls, energy management control or information systems fully integrated into a business customer’s operations, and onsite generators deployed as backup to network service. Policymakers may find it appropriate to invest in customer education and/or technology rebate programs, using ratepayer or public benefits funds, to defray some of participating customers' initial costs, especially if they are barriers to the achievement of demand response potential.

- *Ongoing costs* are incurred by customers when they respond to high prices or demand response program events. These costs may be measurable financial costs (e.g., lost business activity, rescheduling costs such as employee overtime pay, fuel and maintenance costs from operating onsite generation) or more abstract measures of the value of electricity (e.g., the inconvenience or discomfort associated with load reductions).

Various system-wide costs are incurred in implementing demand response, which should be considered in assessing cost-effectiveness.

A variety of *system-wide costs*, which may be passed through to ratepayers or borne by utility or LSE shareholders, are associated with implementing demand response and require consideration in evaluating benefits. These include *initial costs* as well as *ongoing costs* for certain demand response options (see Table 0-1).

Initial costs can be organized into several functional categories, as follows:

Metering and communication system upgrade costs can present a significant barrier to widespread implementation of price-based DR.

- *Metering/communication system upgrade costs*. Customer retail rates typically charge only for the monthly volume of energy consumed, and for larger customers for maximum monthly demand. Time-varying tariffs (e.g., RTP, CPP) requires chronological measurement of energy usage or demand. This is typically accomplished by installing advanced metering systems (AMS) that measure and store energy usage at intervals of one hour or less and include communication links that allow the utility to remotely retrieve current usage information whenever need.[22] Metering and communications system upgrade costs depend on the existing technology as well as the applicable customer classes. Because the aggregate costs may be substantial, they can present a significant barrier to widespread implementation of time-varying tariffs especially for small and medium-sized customers and often raise cost responsibility and recovery issues. Advanced metering issues are discussed in the textbox below.

- *Utility billing system* upgrades may be necessary for some demand response options (e.g., RTP, CPP) because most legacy systems are not equipped to handle time-varying costs or usage. Pricing hourly (RTP), or having provision to price some hours differently (CPP), requires changing the way metered data are collected, processed, and stored.[23]

[22] Note that for some pricing applications (e.g., TOU rates) only usage by daily pricing period (peak and off-peak) needs to be recorded.
[23] RTP (and/or CPP) rates significantly increase the amount of usage data that must be collected (i.e., from two to four observations of customer demand and energy usage per month to at least 720 observations).

Advanced Metering to Support Price-Based Demand Response

Advanced metering is a key technology that enables many utility and customer functions. This textbox addresses four key questions regarding the role and cost of advanced metering.[24]

What is the relationship between price-based demand response and advanced metering? Price-based demand response (e.g., RTP or CPP) requires a tariff that links what the customer pays to the hourly wholesale costs of power. Advanced metering provides utilities with the capability to collect hourly interval or more frequent usage data, which is necessary to support RTP or CPP tariffs.

What is advanced metering? There are three basic types or classes of meters.

- *Conventional "kilowatt-hour" (kWh) meters* account for more than 90% of the current meter population. They record cumulative energy usage and are usually read once each month during an on-site visit by a utility employee.
- *Automated meter reading systems (AMR)* add a low power transceiver, a communication link, to a conventional kWh meter. The transceiver allows the meter to be read from a utility vehicle that drives by the customer site. These meter systems are usually limited by communication capability to collecting a single cumulative kWh reading. AMR speeds up the metering reading function and reduces utility personnel costs.
- *Advanced metering systems (AMS)*, also referred to as *advanced metering infrastructure (AMI)*, provide two features that distinguish them from conventional and AMR systems: (1) the capability to measure and store energy usage at intervals of one hour or less and, (2) a communication link that allows the utility to remotely retrieve current usage information to support customer billing and other utility operational functions.

Aren't advanced meters expensive? Advancements in communications and solid-state technology have reduced the cost of AMI to about $100 per meter if deployed system-wide. Costs to enhance and/or upgrade utility customer information and billing systems are extra. Several recent studies suggest that per-meter hardware and installation costs for advanced metering systems may be comparable to the cost of a new AMR system (King 2004).

What factors should be considered when evaluating the costs and benefits of advanced meters? Advanced metering (AMI) evaluations should consider three major categories of cost and benefit impacts:

- *Utility Operational Impacts:* AMI is first and foremost a technology for automating and improving basic utility operations. Interval metered customer usage data is essential to support billing, outage management, complaint resolution, forecasting, real-time dispatch, rate design and other utility functions. Benefits such as reductions in theft that do not impact utility revenue requirements also need to be addressed. Operational savings alone economically justified all 13 major AMI installations undertaken in North America through 2005. Utility business case analyses should account for the net impact of forecasted operational savings in estimating changes in the utility's revenue requirement from AMI deployment.
- *Demand Response Impacts:* AMI enables RTP, CPP and other forms of performance-based demand response.
- *Societal Impacts:* Societal impacts include improved customer service, environmental, equity and other benefits from more efficient utility operation.

Billing invoices must also be expanded to provide detailed, hour-by-hour accounting. Some utilities and load serving entities can accommodate these new pricing schemes at moderate cost if their existing billing systems are compatible with detailed usage accounting, while others may need to completely revamp or replace their entire billing systems (depending on the number of customers eligible for RTP or CPP).

[24]For more information on Advanced Metering Infrastructure, see http://www.energetics.com/madri/toolbox/.

- *Customer education* about the time-varying nature of electricity costs, potential load response strategies, and available retail market choices is often included in the rollout of demand response options.

Ongoing costs, including program administration and operation, marketing, evaluation, and customer recruitment costs, apply to incentive-based demand response programs and optional pricing tariff options that are offered in addition to customers' standard electricity tariff. For incentive-based demand response programs, additional costs also include payments to participating customers. For most default-service price-based options, there are no incremental ongoing costs relative to any other default-service tariff. However, depending on the type of metering/communication infrastructure used, ongoing equipment operation or leasing costs may apply.

Benefits of Demand Response

The benefits of demand response can be classified into three functional categories: *direct*, *collateral* and *other* benefits (see Table 0-2). Direct benefits accrue to consumers that undertake demand response actions, and collateral and other benefits are enjoyed by some or all groups of electricity consumers. Direct and collateral benefits can be quantified in monetary terms. Other benefits are more difficult to quantify and monetize.

Participant Benefits

Customers who adjust their electricity usage in response to prices or demand response program incentives do so primarily to realize *financial* benefits. In addition, they may be motivated by implicit *reliability* benefits (see Table 0-2).

- *Financial benefits* include cost savings on customers' electric bills from using less energy when prices are high, or from shifting usage to lower-priced hours, as well as any explicit financial payments the customer receives for agreeing to or actually curtailing usage in a demand response program.
- *Reliability benefits* refer to the reduced risk of losing service in a blackout. This benefit may be associated with an internalized benefit, in cases where the customer perceives (and monetized) benefits from the reduced likelihood of being involuntarily curtailed and incurring even higher costs, or societal, in which the customer derives satisfaction from helping to avoid widespread contingencies. Both are difficult to quantify but may nonetheless be important motivations for some customers.

The level of direct benefits received by participating customers depends on their ability to shift or curtail load and the incentives afforded by time-varying electricity prices and any additional program incentives that are offered.

Collateral Benefits

Demand response, through its impacts on supply costs and system reliability, produces *collateral benefits* that are realized by most or all consumers (see Table 0-2). It is these collateral benefits, which have system-wide impacts, that provide the primary motivation for policymakers' interest in demand response.

Table 0-2. Benefits of Demand Response

Type of Benefit	**Recipient(s)**	**Benefit**		**Description/ Source**
Direct benefits	Customers undertaking demand response actions	Financial benefits		• Bill savings • Incentive payments (incentive-based demand response)
		Reliability benefits		• Reduced exposure to forced outages • Opportunity to assist in reducing risk of system outages
Collateral benefits	Some or all consumers	Market impacts	Short-term	• Cost-effectively reduced marginal costs/prices during events • Cascading impacts on short-term capacity requirements and LSE contract prices
			Long-term	• Avoided (or deferred) capacity costs • Avoided (or deferred) T&D infrastructure upgrades • Reduced need for market interventions (e.g., price caps) through restrained market power
		Reliability benefits		• Reduced likelihood and consequences of forced outages • Diversified resources available to maintain system reliability
Other benefits	• Some or all consumers • ISO/RTO • LSE	More robust retail markets		• Market-based options provide opportunities for innovation in competitive retail markets
		Improved choice		• Customers and LSE can choose desired degree of hedging • Options for customers to manage their electricity costs, even where retail competition is prohibited
		Market performance benefits		• Elastic demand reduces capacity for market power • Prospective demand response deters market power
		Possible environmental benefits		• Reduced emissions in systems with high-polluting peaking plants
		Energy independence/ security		• Local resources within states or regions reduce dependence on outside supply

Collateral benefits can be categorized functionally as *short-term* and *long-term market impacts* as well as *reliability* benefits:

- *Short-term market impacts* are the most immediate and easily measured source of financial benefits from demand response. Broadly speaking, they are savings in variable supply costs brought about by more efficient use of the electricity system, given available infrastructure. More efficient resource use, enabled by building better linkages between retail rates and marginal supply costs, translates to short-term bill savings to consumers from avoided energy and, in some cases, capacity costs. Where customers are served by vertically integrated utilities, short-term benefits are limited to avoided variable supply costs. In areas with organized spot markets, demand response also reduces wholesale market prices for all energy traded in the applicable market. Reductions in usage during high-priced peak periods result in a lower wholesale spot market clearing price. The amount of savings from lowered wholesale market prices depends on the amount of energy traded in spot markets, rather than being committed in forward contracts.[25]

- *Long-term market impacts* hinge on the ability of demand response to reduce system or local peak demand, thereby displacing the need to build additional generation, transmission or distribution capacity infrastructure. Because the electricity sector is extremely capital-intensive, avoided capacity investments can be a significant source of savings. However, for demand response resources to reduce capacity costs, it must be available and perform reliably at high-demand periods throughout the year because it is displacing other capacity resources.

Demand response also provides reliability benefits, reducing the probability and severity of forced outages.

- *Reliability benefits* refer to reducing the probability and severity of forced outages when system reserves fall below desired levels.[26] By reducing electricity demand at critical times (e.g., when a generator or a transmission line unexpectedly fails), demand response that is dispatched by the system operator on short notice can help return electric system (or localized) reserves to pre-contingency levels.[27] These reliability benefits can be valued according to the amount of load that demand response load reductions removed from the risk of being disconnected and the value that consumers place on reliable service (the "value of lost load").

Appendix B provides a more detailed discussion of the collateral benefits of demand response to assist policymakers' understanding of economic efficiency gains, avoided capacity benefits and capacity program design and valuation issues, the impact of different market structures on the timing and distribution of short-term and long-term demand response benefits, and the identification and valuation of reliability benefits.

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[25] Many load-serving entities currently purchase a substantial portion of their electricity in ISO-administered spot energy markets. In New York, a state with organized wholesale markets and retail competition, over 50% of electricity is traded in day-ahead and real-time spot markets, with the rest settled in forward contracts. In New England, about 40% of the electricity volume is traded in ISO-NE's spot markets, with about 60% committed in forward contracts.

[26] At times, system dispatchers are faced with either shutting off load to parts of the system, or risk an outage that affects many more customers and load. The loads that are shut off depend on exigent circumstances. Demand response reduces load and thereby lowers the likelihood of the need to impose forced outages. It also reduces the amenity impact of a given level of load shedding because it is distributed among customers according to their willingness and ability to curtail (given appropriate incentives) rather than, for example, cutting off all customers and all load served by a given substation.

[27] Dispatchable demand response resources include direct load control programs, interruptible/curtailable rates and emergency demand response programs. Reliability benefits derive from curtailments undertaken when all available generation has been exhausted and only load reductions can serve to restore system reliability to acceptable levels.

Other Benefits

Demand response can provide several *other benefits* that accrue to some or all market participants but are not easily quantified or monetized:

- *More robust retail markets.* In competitive retail markets, default-service RTP can stimulate innovation by retail suppliers (Barbose et al. 2005), and ISO/RTO-administered demand response programs can provide value-added opportunities for marketers (Neenan et al. 2003).
- *Improved choice.* Demand response can provide expanded choices for customers in varying retail market structures (e.g. states with or without retail competition) through additional options to manage their electricity costs.

Demand response can reduce the potential for generators to exert market power by with-holding supply.

- *Market performance benefits.* Demand response can also play an important role in mitigating the potential for generators to exert market power in wholesale electricity markets by withholding supply in order to cause prices to increase. Price-responsive demand mitigates this potential because demand reductions in response to high prices increase suppliers' risk of being priced out of the market. Demand response can provide this "market performance" benefit even if it is rarely exercised because the *prospect* of demand response may be a sufficient deterrent to prevent generators from attempting market manipulation.
- *Possible environmental benefits.* Demand response may provide environmental benefits by reducing the emissions of generation plants during peak periods. It may also provide overall conservation effects, both directly from demand response load reductions (that are not made up at another time) and indirectly from increased customer awareness of their energy usage and costs (King and Delurey 2005). However, policymakers should exercise caution in attributing environmental gains to demand response, because they are dependent on the emissions profiles and marginal operating costs of the generation plants in specific regions.[28] Emission reductions during peak periods need to be balanced against possible increases in emissions during off-peak hours as well as from increased use of onsite generation.

[28] See Holland and Mansur (2004) for an analysis of regional differences in the impacts of load response on net power plant emissions, and Keith et al. (2003) for an analysis of impacts of demand response resources on net power sector emissions in New England.

Reference: Exhibit B-1, page 4, BCUC Staff IR #1.1

Q18.1 The response to BCUC #1.1 states that savings will occur starting in 2010 and that the $2.592 M in savings will be fully realized in 2011. What are the expected savings in 2010?

A18.1 The expected savings in 2010 is $518,000 as shown in Table A18.1 below:

Table A18.1: Expected Savings in 2010

	($000s)
Meter Reading Cost Savings	(592)
Customer Service Cost Savings	(74)
Operating Expenses	148
Net Savings	**518**

19.0 Reference: Exhibit B-1, page 40

BCUC Staff IR #1.2

Q19.1 Would this capability to display real time prices be one of the required attributes of the meters being acquired or would an upgrade to the meter be required to incorporate this into the AMI system at a later date?

A19.1 The Project will specify that customer and/or system usage data and prices are accessible to customers via an internet logon. AMI meters themselves are not capable of displaying real-time prices. However, some AMI systems have the capability of communicating with in-home display units which would display real-time pricing. The Company would favourably consider technologies that provide this feature at no additional cost. It would not be cost effective to add this capability to the meters after initial deployment of the AMI system.

20.0 Reference: BCUC Staff #20

Q20.1 Assuming a 2% rate of inflation, please confirm that a discount rate of 8% in real terms is equivalent to a 10% discount rate in nominal terms. If so, please explain why the results from Set A using an 8% real discount rate have a negative NPV while the results for the results for Set B using a 10% nominal discount rate have a positive NPV. In FortisBC's view which approach (NPV based on real or nominal dollars) is more appropriate and why?

A20.1 FortisBC confirms that assuming a 2.0 percent inflation rate, a discount rate of 8.0 percent in real terms is equivalent to a 10.0 percent nominal discount rate.

The primary difference is due to the escalation rates assumed for labour and vehicle costs in the nominal dollar analysis. The primary benefit of the Project is the reduction of labour and vehicle costs, and those costs escalate at 3.0 percent and 5.0 percent respectively. Hence higher cost avoidance than the general rate of inflation of 2.0 percent results in a positive NPV. Assuming a 1.0 percent real escalation rate on labour and a 3.0 percent real escalation rate on vehicle costs the Project results in a real NPV benefit of approximately $0.5 million.

The Company considers either approach (NPV based on real or nominal dollars) to be appropriate.

Q20.2 Please explain why the Capital Cost sensitivity analyses (Set C) were performed using nominal dollars as opposed to real dollars.

A20.2 The Company considered that nominal capital costs were more appropriate in these analyses as both labour and vehicle costs were assumed to escalate faster than inflation in both real and nominal terms.

21.0 Reference: BCUC Staff IR #15.1; Appendix 15.2.2; 17.3.2 and 29.1, Exhibit B-1, pages 36-37

Q21.1 Did the 2005 Depreciation Study specifically address the amortization period for the new smart meters as opposed to the existing meters?

A21.1 No. The amortization study was required to determine the treatment of FortisBC's existing plant and equipment.

Q21.2 If not, why is it reasonable to use the same deprecation period?

A21.2 The Company has a number of electronic meters which have been in service for more than 10 years. During this period the failure rate of electronic meters used by the Company has not been significantly higher or lower than the existing mechanical meters.

Q21.3 What depreciation period is used in Alberta and Ontario for smart meters?

A21.3 FortisAlberta used a depreciation rate of 5.72 percent that would suggest an approximate 17.5 year life. As far as the Company can determine, there is no set depreciation rate set for Ontario. As noted in Appendix 15.5.2 of Exhibit B-2, Hydro One Brampton Networks Inc. is applying a 15 year depreciation period.

Q21.4 Please indicate what utilities are the basis for response to BCUC #29.1 that "other utilities are using similar 20-30 years expected life"?

A21.4 The following utilities are the basis for the response to BCUC IR No. 1 Q29.1 (Exhibit B-2):

- Pacific Gas and Electric Company;
- New York State Electric and Gas; and

- Southern California Edison.

Q21.5 Please re-do the rate impact analysis using a 15 year amortization period for smart meters as prescribed by the OEB for the Brampton Hydro analysis (see Appendix 15.2.2, second last page). Note: Please clearly indicate assumptions regarding smart meter replacement costs after year 15.

A21.5 Assuming a 1.0 percent real escalation rate on labour and a 3.0 percent real escalation rate on vehicle costs and a 15 year amortization period results in a real NPV cost of the project of approximately $138,000. The amortization period would not impact the replacement costs after year 15 since the service life of the meters is 25 years.

Q21.6 Please reconcile the 28.6 year life for a smart meter as quoted in BCUC IR #15.1 versus the 25 year life quoted in BCUC IR #17.3.2.

A21.6 The two values are not directly comparable. The 28.6 years noted in the response to BCUC IR No. 1 Q15.1 (Exhibit B-2) refers to the number of years over which the remaining net book value will be depreciated. That value was derived in the 2005 Depreciation Study by dividing the remaining net book value of the meters by the composite remaining life yielding an effective 3.5 percent annual accrual rate.

A survivor curve is a graphical representation of the number of property units (in this case meters) that exist at each age over the life of the original group of assets. There are a number survivor curves used in estimating depreciation commonly known as Iowa type curves. Once the survivor curve is established a number of other estimates including the average life and the remaining life expectancy of the group can be calculated. The 25 year life noted in response to BCUC IR No. 1 Q17.3.2 (Exhibit B-2) is based on the estimated survivor curve for meters.

22.0 Reference: BCUC Staff IR #23.1

Q22.1 What is the basis for assuming a 25% reduction in calls due to billing issues?

A22.1 This assumption, which is clarified to be 25 percent of billing related calls (versus all calls), was based on experience of other utilities that have implemented AMI, the experience of the AMI consultant, and a review of FortisBC call volumes in billing related categories to determine which types of calls would be reduced or eliminated by the implementation of an AMI system.

Examples of results from other utilities include:

Wisconsin Public Service Corporation (approximately 489,000 customers, full implementation in 2004)

- Achieved a reduction in high-bill and estimate complaints of approximately 98 percent.

Austin Energy (approximately 126,000 end-points, implementation in 2002)

- Achieved a 30 percent reduction in meter related calls.

FortisBC's AMI consultant indicated that utilities of similar size have experienced 25-30 percent reductions in billing related calls upon completion of AMI implementation.

FortisBC's "billing" category of calls includes the following:

- High bill complaints;

- Estimating issues;
- Inaccurate reading issues;
- Clarification of billing adjustments; and
- Budget billing questions.

Given these categories, FortisBC believes that it is reasonable to assume the elimination of meter reading estimates and reading errors would reduce this category of calls by approximately 25 percent.

23.0 Reference: BCOAPO #4.2

Q23.1 Please clarify the response provided. Will the vendors be requested to:

a) simply outline the maintenance requirements for the communications network and system used to incorporate data into the CIS or

b) quote on the cost of providing the required maintenance.

A23.1 Vendors will be requested to do both; to outline the maintenance requirements for the communications network and systems used to incorporate the data into the Customer Information System (CIS) that FortisBC will be required to provide internal resources for, and to quote on the cost of any ongoing vendor costs related to maintenance or upgrades to the system.

24.0 Reference: BCOAPO #7.1 and #7.2

Q24.1 On what information does FortisBC base its assumption that the maintenance costs will be the same for AMI-enabled meters?

A24.1 The components of the AMI-enabled meters are essentially the same as the electronic meters that FortisBC uses today with the exception of the communications module within the meter. The older electromechanical style of meter has more moving parts and is therefore more likely to require replacement due to inaccuracy.

The incremental cost of maintaining the communications module within the meter is expected to be offset by the decreased maintenance cost achieved by eliminating electromechanical meters.

Q24.2 What is the basis for FortisBC's assumption that the Network and IT infrastructure will have a 25 year service life? What assumption does FortisBC use for other existing Network and IT infrastructure employed on its system?

A24.2 FortisBC's assumption is that any maintenance required for the AMI Network and IT Infrastructure will be covered within the monthly maintenance fees. If in the future there are proposed upgrades to these systems, it is assumed that these would be identified as separate projects and evaluated on their own merit.

25.0 Reference: Mr. Alan Wait #8

Q25.1 Once the new AMI system in operational, does FortisBC plan on reducing the associated charges under Rate Schedule 80 so as to reflect the lower cost of doing soft meter reads?

A25.1 The $6.00 charge provided for in Schedule 80 is for a transfer of account where no physical meter reading is required. Since this describes the normal process should an AMI system be in place, it is anticipated that this charge can correctly be applied unchanged.

Project No. 3698493: Advanced Metering Infrastructure (AMI) Project
Requestor Name: Mr. Alan Wait
Information Request No: 2
To: FortisBC Inc.
Request Date: March 5, 2008
Response Date: March 19, 2008

Q1 Ref. Wait IR #11

Can FortisBC confirm that a PLC system is completely adequate for all the meter readings presently used by FortisBC?

A1 Confirmed.

Q2 **Will the new AMI meters for residential be capable of demand readings, if in the future residential customers have a demand component in the billing?**

A2 Some technologies provide a demand read from residential meters while others do not. Although this capability is not a project requirement, the RFP will have the vendor outline whether or not this is possible.

Q3 Would the new AMI meters be capable of making note of voltage problems, over and under, and reporting such with time, duration and customer power draw at the occurrence of the voltage problem?

A3 It is not a requirement that the AMI system be capable of reporting voltage (see Table 7.1 in the CPCN Application, Exhibit B-1). However, both the RF and PLC AMI systems used for costing purposes in the CPCN Application included the ability to read voltage as part of a standard meter offering. The AMI system is not capable of reporting customer power draw at any time other than the scheduled kW.h reading times.

Q4 Ref. Wait IR#14

How many substations in the system would not require PCL communications equipment and could be served by the RF towers under FortisBC's present plan?

A4 If an RF technology was chosen, all customers would be served by RF towers. In regards to the hybrid option, vendors will be asked to suggest the optimum mix of RF and PLC technologies. Initial discussions with vendors suggest that if the Kelowna area were served by RF technology, this would remove the requirement for eight substations to have PLC communications infrastructure installed.

Q5 Ref. App. A, P.44, L23&24 A PLC system can generally reach all end points serviced by the utility. Under what circumstances might the PLC system be unable to read a meter?

A5 Possible exceptions to the PLC technology reaching all end-points are as follows:

1) in any cases of third party sub-metering beyond the FortisBC meter; or
2) in cases of high harmonic content on the power line.

Whether or not either of these scenarios will be an issue for FortisBC's AMI implementation will be verified during the RFP process.

Q6 Are the AMI meters a single unit, one type for PLC and a different meter for RF? Or are there interchangeable parts, which makes the meters more flexible for either system, or for future changes in technology such that the whole meter need not be replaced to upgrade reporting?

A6 While the basic meter functions for each type are the same, the difference is in the communications module within the meter. In most cases, if a customer was switched from PLC to RF or vice versa, the meter would have to be removed, the communications module changed and the meter re-sealed.

Q7 Can FortisBC provide a copy of a brochure showing the type of AMI meter they are proposing, which shows the various parts and the operation of the meter?

A7 Included as typical examples in the following attachments are brochures for residential AMI metering endpoints from Hunt Technologies LLC, Elster and Tantalus Systems Corp. Please see Attachments 7a, 7b, and 7c.

EnergyAxis® REX® meter

The EnergyAxis REX meter is a state-of-the art AMI meter that provides significant value in residential applications by lowering operating costs and improving customer satisfaction.

Residential excellence

As a component of the EnergyAxis System, the REX meter brings advanced metering infrastructure capabilities to residential metering applications. Utilities can obtain interval data, bidirectional energy, critical tier, and time-of-use (TOU) data through the EnergyAxis network. REX meters are available in standard residential metering form factors (1S, 2S, 3S, 4S, and 12S).

Utilities can also reduce or eliminate the need to send out technicians to connect or disconnect electrical service by ordering REX meters with the optional internal service control switch.

The data you need

As a residential endpoint in the EnergyAxis System, the REX meter offers the following information:

- Total and 4-tier energy for the primary metered quantity, selected as one of kWh-delivered, kWh-sum (delivered + received), or kWh-net (delivered – received)
- Total kWh-received
- Demand data for two quantities, each configured as total demand or demand for a specific TOU tier
- Per phase voltages
- Interval data for the primary metered quantity in 15-, 30-, or 60-minute interval lengths

Additionally, the meter reports numerous status, warning, and error conditions. All measured data is stored in nonvolatile memory.

Internal service control

Instead of manually removing or installing a meter for service changes, the optional service control switch can remotely connect and disconnect power to a consumer.

Additionally, the REX meter can be programmed to automatically disconnect power when the demand reaches a programmed threshold and to restore power a set number of minutes after the end of the demand interval. To ensure safety, the REX meter verifies that no load side voltage is present before it re-closes the service control switch.

The service control switch is available for Forms 1S, 2S, and 12S meters, and it must be specified at the time of ordering.

elster

Through its open architecture, the REX meter is able to integrate with third party load control devices, demand-side management devices, in-home displays, programmable thermostats, and pre-payment services.

Network functionality

Electricity meter data is directed through the mesh network to the local area collector, where it is stored for retrieval by Metering Automation Server (MAS). In addition, all electricity meter data is available to the utility on request directly from the endpoint, allowing the highest level of customer support and billing accuracy.

To optimize EnergyAxis network communications, each REX meter may act as a repeater. This enhances the robust, mesh communication network, maximizing the communication range of each collector.

The meter obtains time directly from the EnergyAxis collectors. This reduces the initial cost and future maintenance expenses because a battery is not required in each meter.

All REX meters in the EnergyAxis System are uniquely identified by a factory programmed ID. The ID links the meter data to a specific consumer account for accurate billing and enhanced customer support. A second unique identifier is implemented across EnergyAxis to assure the utility's meters are all on the same mesh network.

Outage and restoration functionality

The REX meter provides support for utility outage and restoration management, enabling the utility to more quickly identify the scope of outages and to receive positive restoration messages to validate that power has been restored to every endpoint.

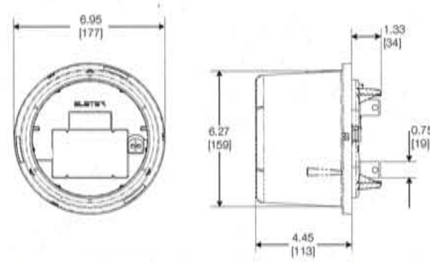
The REX meter also provides the following information that may be used to calculate outage indices:

- Total number of momentary outages, where the definition of a momentary versus sustained outage is configurable
- Total number and cumulative time of sustained outages

About Elster Group

Elster Group is the world's leading manufacturer and supplier of highly accurate, high quality, integrated metering and utilization solutions to the gas, electricity, and water industries. In addition, through its subsidiary Ipsen International, it is the leading global manufacturer of high-level thermo-chemical treatment equipment.

The group has over 8,500 staff and operations in 38 countries, focused in North and South America, Europe, and Asia. Elster's high quality products and systems reflect the wealth of knowledge and experience gained from over 170 years of dedication to measuring energy and scarce natural resources.



Form 2S dimensions in inches [millimeters]. For reference only. Do not use for construction.

Meter specifications

Operating ranges		
Voltage	Nameplate nominal	Operating
Forms 1S and 12S	120 V	96 V to 144 V
Form 2S	240 V	192 V to 288 V
Forms 3S and 4S	120 V to 240 V	96 V to 288 V
Current	0 to Class ampere rating	
Frequency	Nominal 50 Hz or 60 Hz ±5 %	
Temperature	-40 °C to +85 °C (inside meter cover)	
Humidity	0 % to 100 % (noncondensing)	
General performance characteristics		
Starting current	Forms 1S and 3S	10 mA for Class 20 100 mA for Class 200
	Form 2S	80 mA for Class 320
	Forms 2S and 12S	50 mA for Class 200
	Form 4S	5 mA for Class 20
Startup delay	Less than 2 seconds from power application to pulse accumulation	
Creep 0.000 A (no current)	No more than 1 pulse measured per quantity, conforming to ANSI C12.1 requirements.	
Primary time base	Relative time is maintained by a crystal; real time is provided by the network	
Communication frequency	902 MHz to 915 MHz (unlicensed)	
Communication rate	900 MHz radio 17,600 bps	

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200709A

Hunt FOCUS

An ADI Endpoint

TS2 Specification Sheet

Two-way communication with direct-register read

The TS2 Turtle® System enables two-way communication between the utility and the meter using patented ultra narrow bandwidth technology to transmit data. This technology relies on current, rather than voltage, so the transmission of data is not affected by line length or line conditioning devices. Within a Turtle AMR system, the TS2 FOCUS endpoint provides continuous data transmission to the utility. This allows for four time-of-use registers with 15 minute time interval resolution, as well as a maximum demand register available in daily 15, 30 or 60 minute intervals. Programmable to return a variety of data transmission options, the TS2 FOCUS endpoint allows each utility to select the meter data that is of most use to their organization.

Using a TS2-equipped FOCUS® meter within a Turtle AMR system allows a utility to monitor power consumption on a daily basis and offers maximum demand and time-of-use billing functions. Using Hunt Technologies' power line carrier-based Turtle System technology, the TS2 FOCUS endpoint reads data values directly from the meter register and transmits usage and demand data to the utility over the power line. This direct-register read allows the endpoint to provide more data values, such as precision voltage reads.

The FOCUS meter platform

When combined with modular AMR communication technologies, such as Hunt Technologies' TS2 module, the FOCUS meter delivers benefits not found with other solid-state platforms. Highly accurate load performance and the use of a field-proven Digital Multiplication Measurement Technique ensure reliability and dependability during the entire life of the FOCUS meter. The unique single-circuit board design, with fewer connectors and fewer parts, increases reliability and contributes to better overall endpoint performance. Endpoint diagnostics are accomplished more quickly and more accurately because the FOCUS metrology and modular AMR communications are separated. The single-circuit board design also facilitates an easier retrofit at a less costly price than designs that incorporate module communications with meter display functionality. Furthermore, the meter circuit-board is mounted in the face of the meter, away from potentially damaging current coil heat that can be generated under heavy loads or other conditions.

TS2 FOCUS endpoints are available in 1S, 2S, 2SE, 3S, 4S, 12S and 25S meter forms and are ideal for expanding a currently installed Turtle system.

Solution highlights:

- Reads metrology data values directly from the meter register
- Service voltage and average voltage reads from the meter accurate to ±1 percent
- Outage detection and restoration notification
- Peak demand and time-of-use billing
- User-configurable data transmission options
- Remote programming from the billing office
- Tamper detection
- Economical price

Landis+Gyr

Hunt Technologies, Inc.

Hunt FOCUS

Technical Specifications

Meter Compatibility

FORM	CLASS	VOLTAGE
1S	100	120
2S	200	240
2SE	320	240
2K	480	240
3S	10/20	120
3S	10/20	240
4S	10/20	240
12S	200	120/208
25S	200	120/208

Functional Specifications

Tamper Detection:	Power outage detection
Meter/Module Interface:	Direct register read
Application:	Two-way power line carrier

Operational Specifications

Transmit Frequency:	Ultra narrow bandwidth PLC

Environmental Specifications

Operating Temperature:	-40°C to +85°C
Operational Relative Humidity:	5% to 95% (non-condensing)

Surge Withstand Specifications

ANSI C37.90.1 - 1989 Surge withstand capability

ANSI C12.20 - 2002 Electrical Fast Transient/Burst

ANSI C12.20 - 2002 Effect of High-Voltage Line Surges

2800 Duncan Road | Lafayette, IN 47904 | Phone: 765.742.1001 | Fax: 765.742.0936 | www.landisgyr.us

> TC-1210

TPM Controller -GE I-210

Smart communications for GE singlephase electronic meters

Tantalus adds two-way communications to electronic GE I-210 singlephase watthour meters. Combining GE's precise metering technology with Tantalus' real-time, multi-application data network establishes a high performance bi-directional communications pipeline to fully support advanced metering, and the rich data requirements of dynamic pricing and demand response programs.

The TC-1210 transmits the interval data needed for TOU, CPP, or RTP billing programs in periods as low as five minutes. Utilities can use the TC-1210 to closely monitor power quality (voltage blinks, sags and swells) and detect outages remotely, in real time. The result is precise load profiling coupled with a new level of reliability and operational performance.

Fast, round-the-clock access to meter data enables CSRs to respond promptly and insightfully to customer inquiries. That translates into fewer truck rolls needed to investigate problems and perform off-cycle reads, reduced downtime resulting from faster repairs, and all the information needed to provide unsurpassed, cost-effective customer service.

The GE I-210 provides the accuracy and reliability required by progressive utilities. The TC-1210 delivers data when it's needed and where it's needed – billing, CIS, OMS, and other applications – to ensure operational excellence, attentive customer service, and airtight regulatory reporting. TUNet – the Tantalus Utility Network – also helps accelerate ROI. It gives utilities the freedom to surgically deploy modules to prioritized customer segments or geographies or as part of a full scale advanced metering roll out.

Advantages

> Reports kWh energy consumption, voltage and outage

> Reports interval consumption – as low as 5 minutes – for dynamic pricing programs

> On-request reads allow customer service to respond to inquiries and closely monitor endpoints remotely, in real time

> Remotely programmable operating parameters allow a utility to easily tailor performance measurements

> Measures voltage from 170 to 260 V; accurate to ±1%

> Reports voltage sags / swells / blinks to help ensure high quality power delivery to each home

> Field initiated outage and restoration alerts instantly notify staff of critical events and reduce field time

> Under-the-glass design fits into tamper-resistant GE I-210

> Non-volatile memory maintains data during outages

> Automatically negotiates the best path to TUNet to ensure reliable communication

> Optional remote disconnect / reconnect available through the RD-1000

Meter Forms Supported

> 2S

Radio

> Frequency range: 902 – 928 MHz: license exempt

> Transmit power: 0.5 watts (27 dBm)

> Antenna: built-in

Power

> Supply: 240 VAC from AC line mains

> Quiescent power: 1.9 watts

Physical

> Operating temperature range: -40° to +158° F / -40° to +70° C

> Operating humidity range: 5% to 95% non-condensing

Approvals / Standards

> ANSI C12.1 & C12.20

> FCC for CFR Title 47 Part 15b

> Measurement Canada

Versatile. Affordable. Easy to install. The TC-1210 transforms a GE I-210 into a two-way communications device to support dynamic pricing, demand response programs, remote diagnostics, and industry leading outage notification.

www.tantalus.com | 604.299.0458

Tantalus

Q8 Is the hybrid system considered the most cost effective to install, or is going to RF rather than PLC in some cases, a matter of greater communications capacity?

A8 Until the RFP is completed by the various vendors, it is unknown which technology (PLC, RF or Hybrid) will be most cost effective based on the required functions. The greater communications capacity and flexibility offered by RF technologies will be an issue that will be considered when comparing the various technologies, but only as it relates to the required functions and features listed in Table 7.1.

Q1: Reference: B-2 Karow IR#1 Q1, Q2, & Q 13 - Fortis Response A1 & A13

Q1 please provide specifications about the meter reading device with re:
a brand/make of reader,
b when patented
c please provide patent #,
d actual patent paper's claim and description
e where manufactured and distributed by whom

Although it is understood, that a certain meter reading device has not been chosen yet, nevertheless it is urgently requested to provide answers to IR#1Q1, IR#1Q2 and IR#1 Q13 about 2-3 typical metering system that might possibly be used and /or FortisBC might have in mind.

A1 FortisBC does not believe this information is relevant to this Application, particularly since a technology vendor has not yet been chosen. The requested information will vary for each specific vendor, so providing information for two or three vendors would not be indicative of the responses of the others. Please also refer to the response to Karow IR No. 2 Q2 and Wait IR No. 2 Q7 (Exhibit B-4).

Q2: Reference: B-2 BCUC IR#1 Q29.1 Fortis Response A29.1

Q29.1 What is the expected life of the AMI system meters? Please provide any support for the expected life estimate, including actual experience, where available.

A29.1 The expected life of the AMI system meters is 25 years. The meters are fundamentally the same as existing electronic meters which typically last beyond 25 years. FortisBC understands that other utilities are using similar ranges at 20 – 30 years expected life.

FortisBC refers to other utilities using the new meter reading system. Please provide info material about other systems that other utilities are using.

A2 Some representative examples of the technologies other utilities are using are as follows:

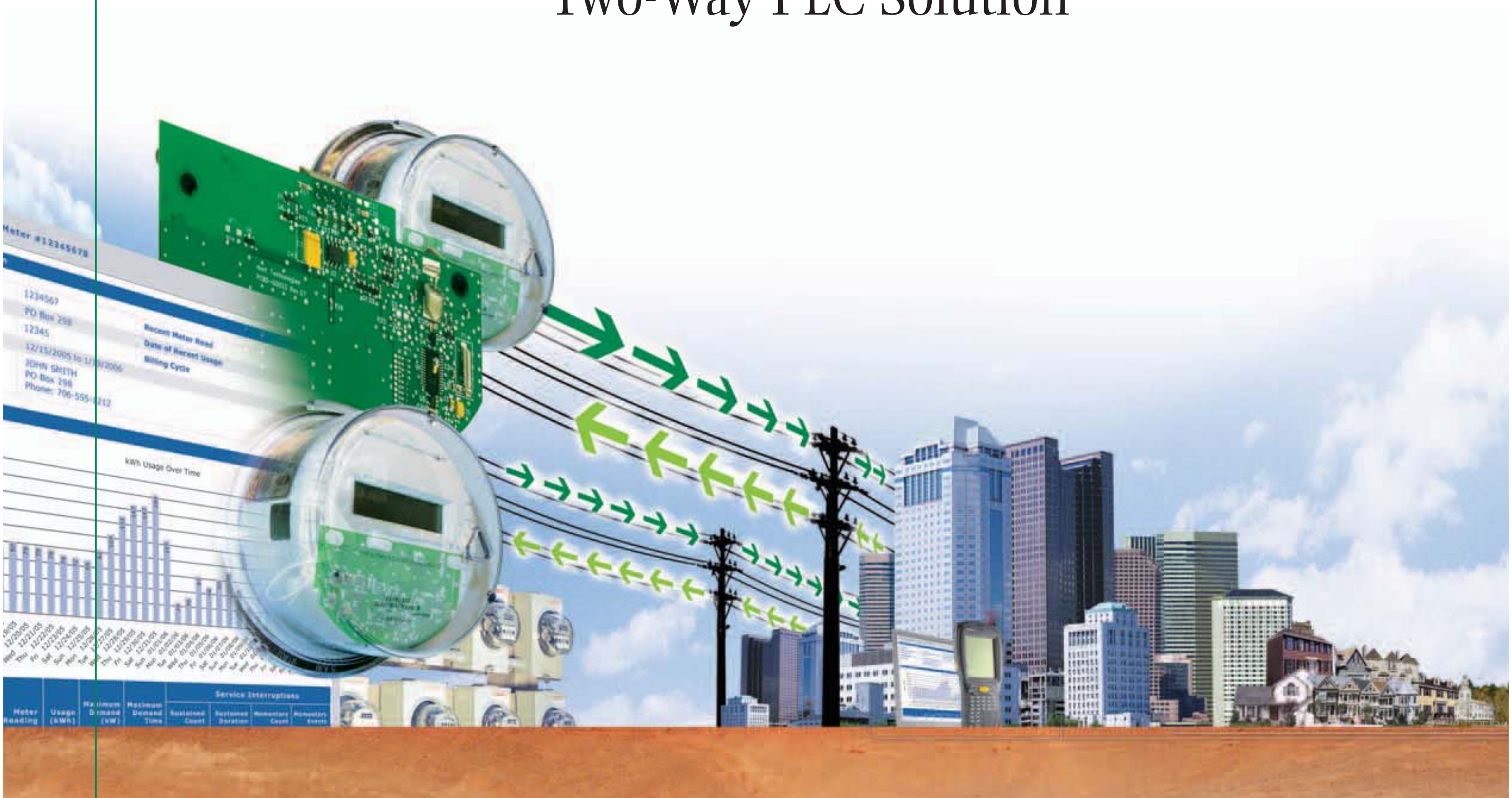
FortisAlberta is using a Hunt Technologies AMI system. Brochures for both the PLC and RF Hunt system are attached.

Chatham Kent Hydro is using a Tantalus AMI system. Information on the Tantalus system can be found on their website: www.tantalus.com/sub_architecture.html

Alliant Energy has chosen a Sensus system for AMI. A brochure for their technology is attached.

The TS2 System

The Industry's Most Powerful And Flexible Two-Way PLC Solution



Two-Way | Urban | Suburban | Rural | Electric | Water | Gas | Multi-Utility | Always On™ | 24/7 Support

The Possibilities Are Endless™

Hunt Technologies

The TS2 Solution:
Automatically Turn Data Into Information

The ability to monitor meter data and make critical decisions has never been easier than with the Hunt Technologies' TS2 two-way power line carrier system. Offering precise and timely information that will automatically improve power delivery, increase billing accuracy and upgrade customer service, TS2 offers utilities unparalleled control.

With Command Center™ as its foundation — the most powerful and interoperable software engine ever created — you get easy-to-use, browser-based access to over 200 data values and more than 75 automated and customized reports, offering endless possibilities for monitoring, analysis, planning and resource management.

Critical Functionality That Improves Resource Management

- Meter reading and diagnostics
- Outage and restoration detection
- Demand billing
- Remote disconnect
- Power quality monitoring
- Load profiling
- Customer service assistance
- Intuitive user interfaces
- Anytime/anywhere access
- Billing extracts and reports
- Distribution network monitoring

For utilities that require powerful, flexible and accurate two-way AMI solutions, the Hunt Technologies' TS2 system is the right choice.

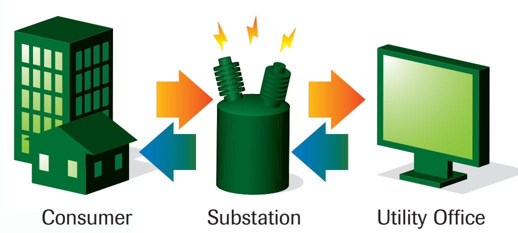
No matter what the topology, the TS2 system delivers unparalleled data collection, meter control and resource planning information. Optimized to improve departmental operations — from customer service, engineering and billing, to distribution, field management and finance — it is **the one AMI system built to evolve with the needs of the industry and your customer base**.

Advanced Two-Way Technologies

The foundation of the TS2 power line carrier system is the combination of our patented ultra-narrow-bandwidth (UNB) technology with frequency division multiple access (FDMA) communication. This allows for true bi-directional, long-distance transmission across a utility's entire infrastructure, and, unlike others, ensures "**Always On**™" continuous monitoring of every single endpoint in your system. "Always On" instantly improves overall system and data delivery efficiency, including load balancing, distribution automation, and outage detection/restoration.

Receipt of downstream on-demand read requests, time-of-use schedule changes or load control activations occur without the risk of interrupting upstream data packets. Additionally, TS2 endpoints communicate without the need or associated costs of repeaters or line conditioning equipment, while ensuring accurate transmission of data from an unlimited number of endpoints.

TS2 is the only AMI system that can monitor over 200 data values – providing endless analytical possibilities



Feature-Rich And Flexible

Compatible with the broadest range of meters in the industry, including electromechanical and solid state single phase or polyphase meters, the TS2 system also enables your utility to **improve customer service, enhance revenue, and meet 2005 Energy Act demand response requirements**, with functionality including:

- Accurate, reliable time-of-use data
- Remote TOU schedule changes
- Enhanced load control capability
- On-demand reads
- Remote connect and disconnect services
- Coincident demand reads
- Remote move-in, move-out readings
- Multi-utility solutions
- Remote programmability
- Field programming – through-the-glass
- True continuous system monitoring
- Outage/Restoration notification
- Phase identification
- Plug-and-play meter deployment
- Tamper and theft detection

Data Protection Means Revenue Protection

Hunt's TS2 system eliminates the inherent risks of lost data because each TS2 endpoint continuously captures and logs meter data in its non-volatile memory for later transmission to the Substation Processing Unit, and then on to your information systems.

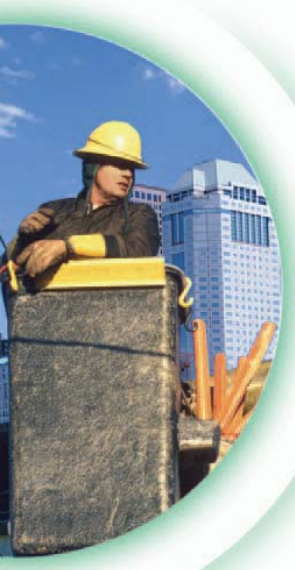
Even in the event of a power failure, the TS2 system's **fault tolerant architecture** ensures that all values are retained for transmission when the system is again operational. You get complete, accurate readings for kWh, 15/30/60 minute time-and-date stamped kW demand data, TOU kWh for four rate periods and momentary interruptions count — guaranteed.

To provide our utility customers with the very highest level of data protection and availability, **data is stored at the Substation Processing Unit for up to 30 days** on a first-in-first-out basis. This provides a superior level of data security.

The TS2 system also lets you use collected data to trim losses due to damaged equipment and theft. By comparing overall substation totals with aggregate meter readings, areas of energy loss can be identified and repaired.

Get The Attention You Deserve

When you partner with Hunt Technologies, you get what no other company in the industry will offer: an iron-clad **performance guarantee**.



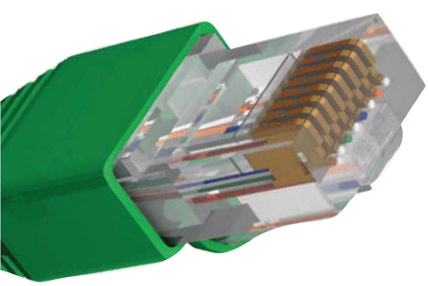
And not just for the hardware and software we sell, but for everything we do: delivering world-class customer service and technical support; developing innovative and cost-effective monitoring technologies; maintaining the highest level of meter compatibility; orchestrating migration and integration procedures, and promoting the industry's best interests nationwide through regulatory involvement.

- **98%** industry expertise rating
- **97%** product satisfaction rating
- **96%** "Best in Customer Service" rating

But most of all, you are guaranteed ingenious approaches to satisfying your company's and customers' needs faster and smarter.

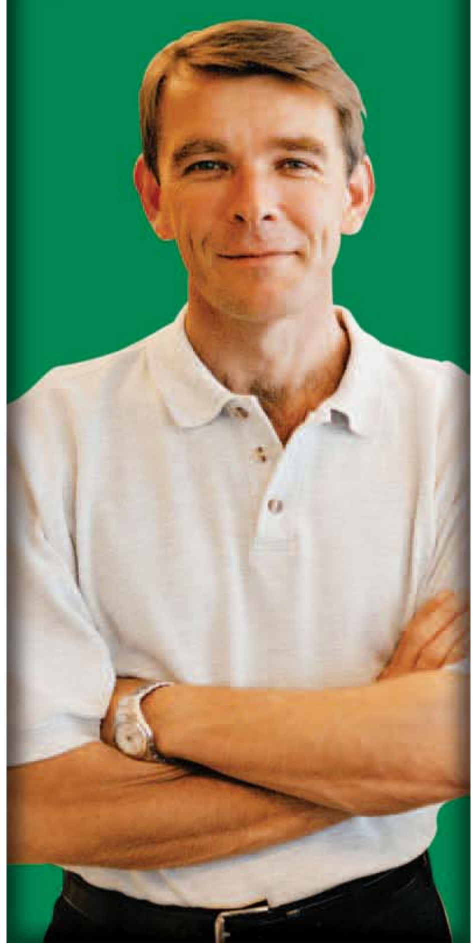
Command Center MSP

Every utility will benefit from Command Center, but not all of them have the IT infrastructure to support it. Which is exactly why we offer Command Center MSP™, **a low-cost, Hunt-hosted managed services package** (MSP) that is highly secure, and delivers all of the power and functionality of Command Center. You even get access to leading edge customer management tools that only Hunt Technologies can offer.



Not only will you improve productivity and performance, you will instantly reduce expenses and the infrastructure associated with AMI data management. From managing servers, and installing upgrades and patches, to eliminating purchases of additional computer hardware, software, licenses, support agreements and systems administration, **Hunt Technologies does everything for you**.

The TS2 solution **takes utilities into the future**, and is flexible enough to provide the features they need to **stay competitive**. And because it complies with the Energy Policy Act provisions for **smart meters**, its technological advantages are clear.



Creating Endless Possibilities for The Utility Industry

Hunt Technologies is a worldwide provider of advanced metering infrastructure (AMI) solutions to investor-owned, rural electric cooperative and public utilities. Using innovative technologies and ingenious strategies, we provide our customers with 100% coverage, 100% functionality and guaranteed satisfaction. Through the combination of Command Center™, the most powerful and interoperable AMI software engine ever created, and our ability to monitor more electric, water and gas meter systems than any other company in the industry, only Hunt Technologies offers utilities endless possibilities to simultaneously satisfy their critical information needs and enhance customer service.

Need proof? No problem.

Just call **1-800-828-4055**
or visit our website at
www.hunttechnologies.com

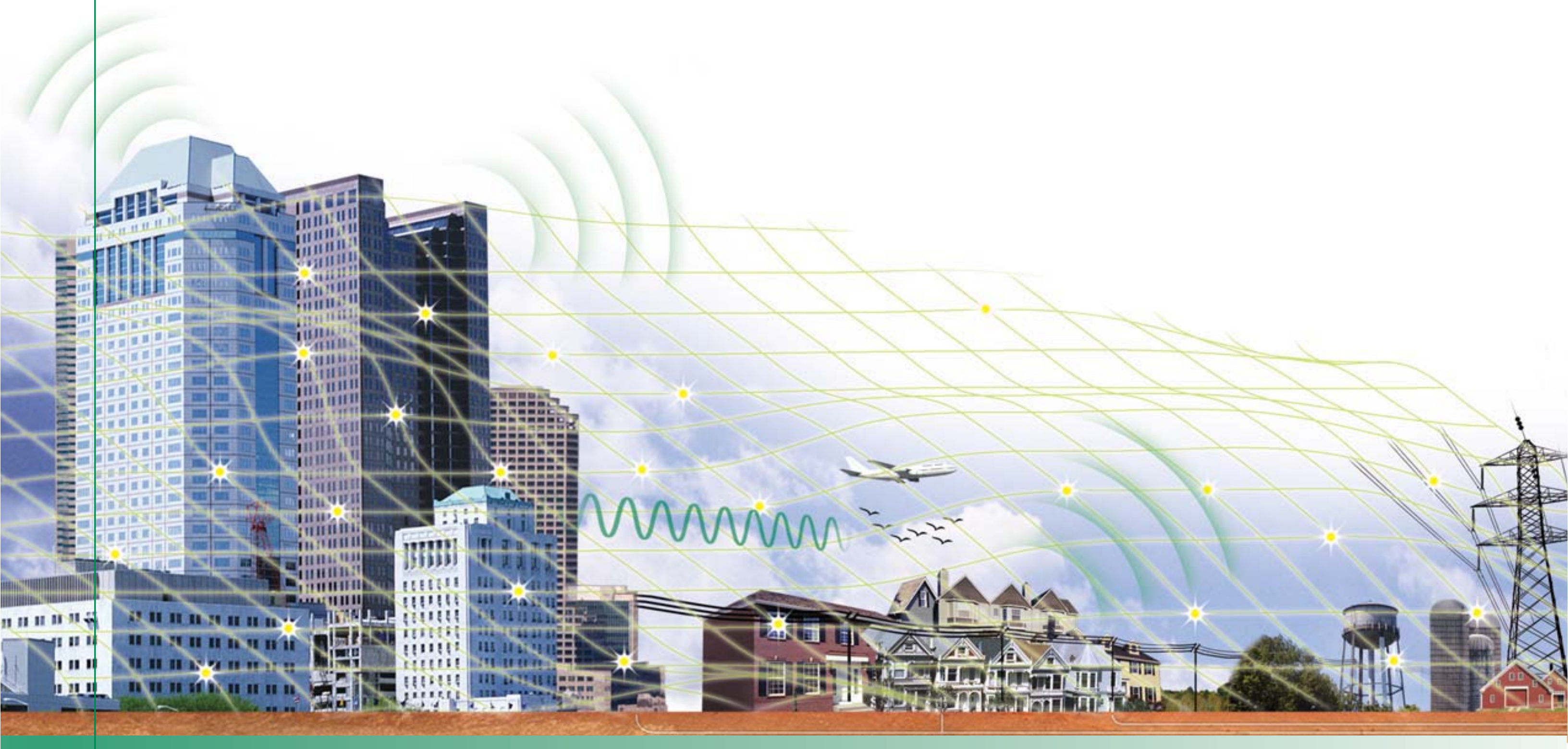
The Possibilities Are Endless™

Hunt Technologies

6436 County Road 11
Pequot Lakes, MN 56472
Phone: 800.828.4055
Fax: 218.562.4878
www.hunttechnologies.com

The StatSignal System

The Industry's Most Efficient, Dynamic Two-Way RF Mesh Solution



Two-Way | RF | Urban | Suburban | Rural | Electric | Auto-Intelligent Routing | Low-Cost | Feature-Rich

The Possibilities Are Endless™

Hunt Technologies

For the only scalable, dynamic, two-way RF solution that increases efficiencies at every touch point, the choice is Hunt Technologies' StatSignal system.

Engineered to enable any utility to acquire volumes of critical customer usage data, and channel it into knowledge that can be used to instantly **affect energy management, customer service, operational infrastructure and billing flexibility**, Hunt Technologies' StatSignal system is without peer. Not only is it **future-proofed** for post-deployment expansion, it provides utilities with the means to meet and exceed federal and state compliance regulations.

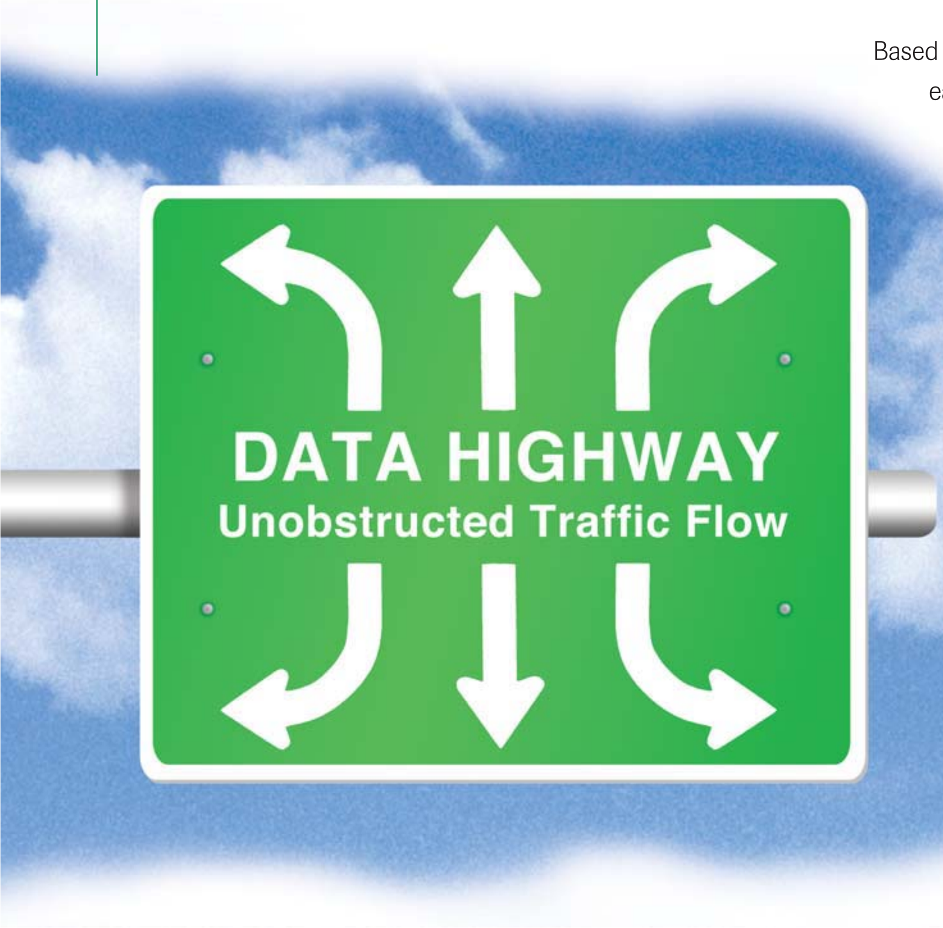
Performance you can count on

- Globally-proven communications technology
- Reliable, flexible, feature-rich
- Minimal infrastructure requirements
- Fast and easy installation and maintenance
- Complete monitoring of residential, commercial and industrial customers

Continuous, "Auto-Intelligent" Data Acquisition And Control

The StatSignal system operates under a single premise: provide utilities with continuous transmission of, and access to, critical customer usage data through **a dynamic, auto-intelligent routing protocol** that delivers maximum control capabilities.

Consisting of **smart endpoints** that are programmed to transmit data and route it "to and through" a series of other endpoints, in the most efficient and reliable way to get to the available collector – similar to a river seeking the path of least resistance as it heads toward the ocean – the StatSignal System mitigates traditional RF communication bottlenecks that drop data and disrupt continuous data flow. If an endpoint realizes that other endpoints are using the same communications route, it utilizes auto-intelligence to dynamically determine – on its own – the best route to transmit the data.



Based on standard local area network (LAN) technology, each endpoint is programmed to communicate via a **proprietary RF Mesh protocol** that operates over the **unlicensed** ISM 902-928MHz FHSS spectrum, thereby allowing it to operate freely and without any restrictions.

The result is a revolutionary communications breakthrough that enables **utilities to acquire, manage and control customer usage data in ways they never imagined.**

Feature-rich, Flexible And Uniquely Cost-efficient

With StatSignal, utilities receive the data they need, when and how they need it. And they can do it without incurring traditionally expensive RF infrastructure costs – which **enables utility revenue quickly and consistently.**

The flexibility of utilizing mass-marketed public wide area networks (WAN) or private WAN networks already owned and operated by some utilities and municipalities – combined with the "virtually free" RF Mesh LAN – greatly **reduces per-endpoint costs** associated with the communication of data. Additionally, there are **fewer collectors required to deploy a fully operational system**, thereby enabling utilities to quickly meet internal needs for operational efficiencies, while also addressing environmental and energy efficiency requirements.

The features you expect:

- Full automation
- Hourly and sub-hourly interval data
- Time-of-use
- Demand reads
- Load profiling
- Power quality monitoring
- Outage/restoration notification
- Remote connect/disconnect
- Demand resets
- Remote firmware updates
- Data encryption
- Theft detection

The benefits you want:

- Peak load management
- Risk reduction
- Distribution planning
- Asset management
- Energy forecasting
- Resource conservation
- Flexible billing cycles
- Real-time billing resolution
- Load balancing

And much more…

Built For Growth And Any Utility Customer Type

The simplicity and power of the StatSignal system does not rely solely on its ability to handle tremendous amounts of critical data, and enable utilities to turn that data into knowledge. The entire system was also **engineered to scale and meet any utility's needs**, no matter what type of customer base it serves, in a time frame that no other RF system can match.

Regardless of whether a utility must accommodate commercial, industrial or residential growth, all meters can be programmed remotely and **fully operational within three days** deployment.

Get The Attention You Deserve

When you partner with Hunt Technologies, you get what no other company in the industry will offer: an iron-clad **performance guarantee**.

And not just for the hardware and software we sell, but for everything we do: delivering world-class customer service and technical support; developing innovative and cost-effective monitoring technologies; maintaining the highest level of meter compatibility; orchestrating migration and integration procedures; and promoting the industry's best interests nationwide through regulatory involvement.

- **98%** industry expertise rating
- **97%** product satisfaction rating
- **96%** "Best in Customer Service" rating

But most of all, you are guaranteed ingenious approaches to satisfying your company's and customers' needs faster and smarter.

The **StatSignal** system enables utilities to **quickly improve operational and customer service efficiencies**, while delivering the functionality necessary **to manage resources** more effectively.

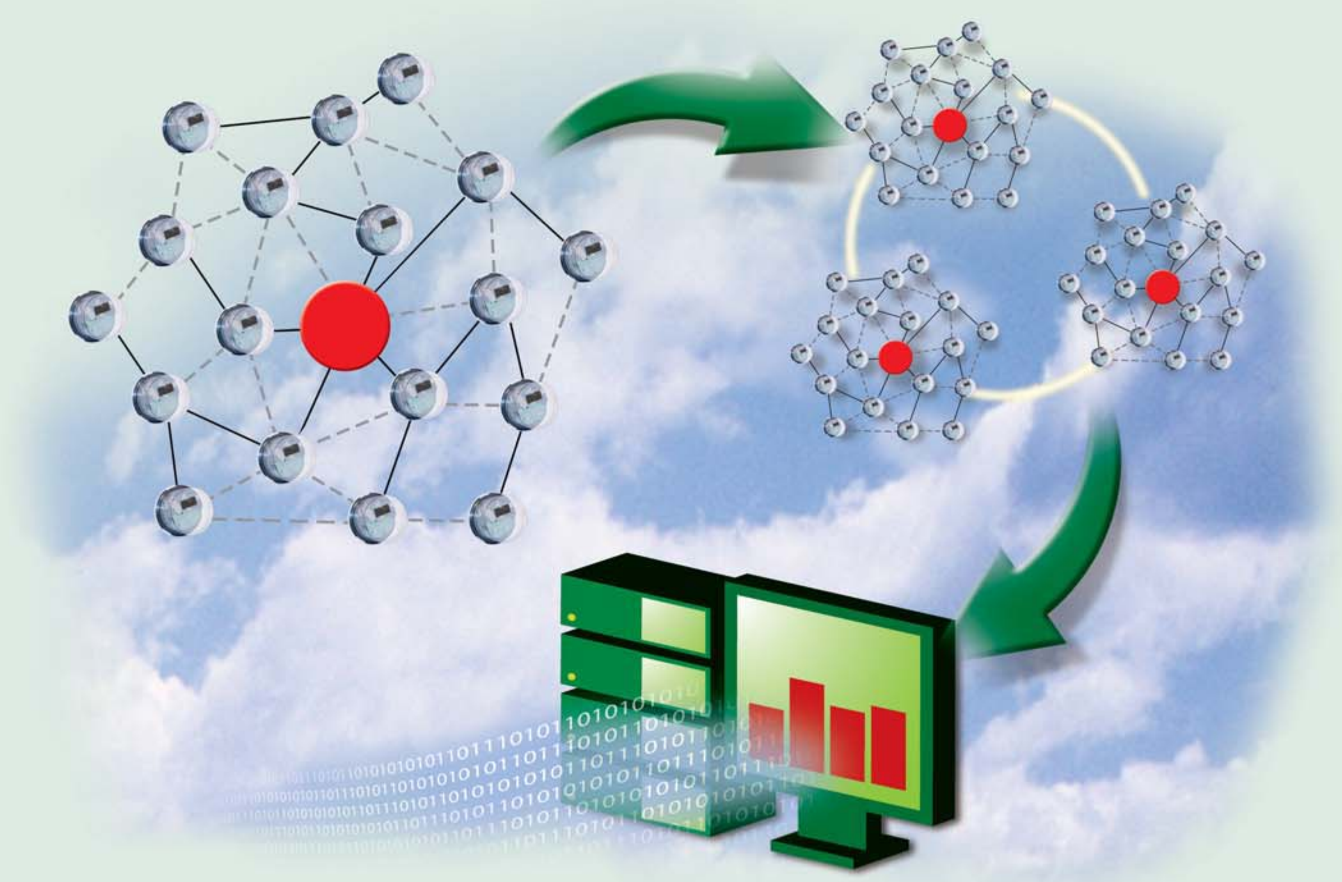
Command Center Software: Turning Data Into Knowledge

The heart and soul of the StatSignal system is Hunt Technologies' Command Center™, **the most powerful and interoperable software engine in the industry**. All data is automatically routed to this easy-to-use, multi-dimensional, browser-based application, which turns raw data into analytically-driven knowledge in the form of over 75 automated and customized reports. And because Command Center is interoperable with your Billing, Engineering, Customer Service, Accounting, MIS, Field Management and other departmental software programs, it allows **collaborative access** to information in ways that other platforms simply don't.

With other applications, you have information. **With Command Center, you have knowledge.**

The StatSignal Solution:
Reliable, Powerful And Intelligent AMI Solutions for Any Utility

The StatSignal two-way, RF mesh, fixed-network AMI system is an exceptionally powerful solution for utilities that require a reliable, accurate and cost-efficient data acquisition system. Engineered as an advanced communications platform that monitors and controls critical residential, commercial and industrial customer data, it is uniquely scalable, auto-intelligent and easy to deploy, enabling any utility to turn data into knowledge.



Advanced Operational, Revenue Generation And Customer Service Benefits

- Reduction in labor force
- Trouble call reduction
- Fewer estimated bills
- Compressing read-to-bill time
- More accurate meter reads
- Less estimated readings
- Faster off-cycle reads
- Greater historical data for all accounts
- Decreased cost of tenant turnover and off-cycle reads
- Access to greater load research data
- Distribution/transmission planning and engineering
- Asset management and utilization
- Transformer load management
- Consolidated billing
- Rate modeling using actual data
- Increased number of pricing plans
- Billing cycle flexibility
- Electronic bill payment

Creating Endless Possibilities for The Utility Industry

Hunt Technologies is a worldwide provider of advanced metering infrastructure (AMI) solutions to investor-owned, rural electric cooperative and public utilities. Using innovative technologies and ingenious strategies, we provide our customers with 100% coverage, 100% functionality and guaranteed satisfaction. Through the combination of Command Center™, the most powerful and interoperable AMI software engine ever created, and our ability to monitor more electric, water and gas meter systems than any other company in the industry, only Hunt Technologies offers utilities endless possibilities to simultaneously satisfy their critical information needs and enhance customer service.

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Fax: 218.562.4878
www.hunttechnologies.com

SENSUS METERING SYSTEMS

Attachment A2c

Advanced Metering Infrastructure Technology for Utilities

FlexNet®

FlexNet System Overview

One-way, two-way, interval data, Time of Use (TOU) rates, real-time metering, load control... Now you can have it all with greater flexibility that ever before!

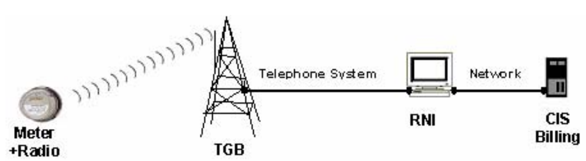
Sensus' **FlexNet** AMI (Advanced Metering Infrastructure) network introduces a new level of simplicity and efficiency to fixed-base AMR, with a reliable and scalable fixed network. Finally, the functional benefits and diversity of AMI come without the penalty of dense infrastructure deployment.

Get daily metering data at an all-in price, competitive with drive-by systems. The patent pending modulation and DSP-based tower receivers reliably communicate with endpoints over 5 - 15 miles. The **FlexNet** system may include both one-way and two-way meter modules, and supports incremental expansion towards saturation deployments at a pace consistent with a utility's needs and budget. **FlexNet** also includes back-end database interfaces and web-based commands and analysis tools.

FlexNet System Components

FlexNet is designed for simple implementation. It includes just three elements:

- Endpoints: electric, gas and water meters fitted with FlexNet radio modules. A handheld installation tool is used in order to assist in the field installation and verify registration to the network.
- Tower Gateway Basestation (TGB): using existing radio towers, antennas are installed at heights of 200'-650', providing coverage of 75 to 300 sq. mi. The TGB includes a Linux computer that communicates to the RNI (see below) via modem
- Regional Network Interface (RNI): consists of modems and Linux computers with backup power. The RNI controls the TGB sites and keeps a 60-day log of metering data. It also includes an SQL database that generates reports for billing and other external system elements. Interfaces are available to a variety of metering databases: Sensus SiMS, Itron MV-90 and Enterprise Edition. Interface can also be performed via XML files or customized per the utility's requirements.

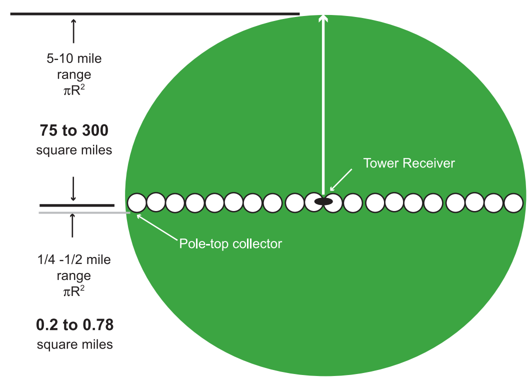


Superior Technology

FlexNet operates on 900 MHz FCC licensed exclusive-use (unshared) frequencies and is the only AMI system that is FCC approved to operate on unshared, primary-use licensed spectrum. The high power transmission, minimal interference of the licensed band and the advanced DSP at the tower receiver enable an exceptionally long-range (5-15 miles) of reliable communication between the meter end-point and the base station tower site.

Pole-top repeaters are not required in the FlexNet system, since the towers provide extensive coverage areas, and also due to additional operation modes:

- 'Boost Mode' is set when a stronger signal is required in order to ensure reception at the TGB.
- 'Buddy Mode' is set in order to relay a signal from a meter that is otherwise beyond the TGB coverage, through a nearby electric meter with better coverage.



One Tower Receiver replaces approximately 400 pole-top data collectors.

Advanced Metering Infrastructure Technology for Utilities

Attachment A2c

System Features and Benefits

- Two-way or one-way functionality
- Over 1 Watt of FCC licensed power output
- Readings and reports: kWh, demand and actual voltage
- Alerts: outage notification, breaker reclosure and low voltage warnings
- Tamper detection: meter removal, meter inversion, reverse rotation
- Interval data for Time of Use applications and consumption correlation

- Demand reads and demand register reset commands
- Load control commands to endpoints
- ANSI C12.19 table selection for C&I meters
- Real time clock calibration for synchronized reads
- Real-time readings on-demand
- Text, rate change notification

- All programmable meter functions accessible via secured website

Summary

Only one system can put you in control of a wide range of fixed network AMI features, including two-way meter communications, and yet remain simple and efficient to deploy and use. The path is clear – choose FlexNet and you are on the fast lane, headed to reap the benefits of advanced metering!

AUTHORIZED SENSUS DISTRIBUTOR

P.O. Box 487 • 450 N. Gallatin Avenue
Uniontown, PA 15401
1-800-METER-IT • 1-800-638-3748
Fax: Direct to Factory
Local: 724-439-7729 • Toll Free: 1-800-888-2403
www.sensus.com (select "North America Water")
Email: h2oinfo@sensus.com

Q3: Reference: B-2 Karow Q5 & Q13 Fortis Response A5 & A13

Q5 all frequencies range applied (also meaning whether each individual ratepayer meter will have different frequency/ies)

A5 This information is not available until such time that a vendor is chosen through the RFP process. Some of the frequencies used by different vendors are shown in the response to Karow IR No. 1 Q13 (Exhibit B-2).

Q13 Please state whether there are other means than wireless meter readings,

i.e. via land-lined telephone/ cable system to a central reader office with a multiplexor system

A13 Technology options available for the Local Area Network (LAN) portion of the AMI system (between the meter and the central collection point) are:

- Spread Spectrum (900 MHz, 2.4 GHz, 802.11b, Zigbee);
- Licensed frequencies (928 MHz, 450 MHz, 220 MHz); and
- Power line carrier (PLC)

Technology options available for the Wide Area Network (WAN) portion of the AMI system (between the central collection point and the office) are:

- Plain old telephone service (POTS);
- Fiber;
- Microwave;
- Wimax;
- Pagenet / Supernet;
- T1 line;
- Interexchange Radio Transmission Technologies (IXRTT); and
- General packet radio service (GPRS).

Q3a From the technical aspect only and without referring to and independently from the WHO/ICNBIRP/Canada Health EMF exposure guidelines (that new meter reader emissions are well below such guidelines) of the above possible used frequencies, please state for each the typical power density (W/square meter) at distances 0.25m, 0.5m, 1.0m, 2.0m, 5.0 m 10.0m 20.0m.

A3a Typical radiated power emission will vary from equipment to equipment so, as a conservative estimate, we provide the estimates for the maximum allowed power emission of any equipment per Industry Canada standards [RSS-GEN, RSS-310, RSS-210, RSS-129]. Table A3a lists expected power densities in W/m^2 for the intentionally emitting equipment as a function of distance.

Table A3a: Maximum power density in units of W/square meter

Equipment	**Frequency (Mhz)**	**Distance (m)**							
			0.25m	0.5m	1m	2m	5m	10	20
Spread Spectrum	902-928 2400-2483.5 5725-5875	**W/m^2**	5.09	1.27	0.318	0.0796	0.0127	0.00318	0.000796
Non Spread Spectrum	902-928 2400-2483.5 5725-5875		0.955×10^{-3}	0.239×10^{-3}	0.597×10^{-4}	0.149×10^{-4}	0.239×10^{-5}	0.597×10^{-6}	0.149×10^{-6}
CDMA	824-849		2.55	0.637	0.159	0.0398	0.00637	0.00159	0.000398

Notes on Table 1: Spread spectrum, Non Spread Spectrum, and CDMA devices are limited to 4W, 0.75mW, and 2W total radiated power, respectively. 802.11b and Zigbee communicate in the 2400-2483.5 MHz band. 928MHz is not a licensed band. Maximum allowed output in 450MHz and 220MHz depends on specific technology used; once specific equipment is selected, a detailed evaluation can be performed. Wimax and microwave do not have a standard frequency allocated; once specific equipment is selected, a detailed evaluation can be performed. Standard for GPRS could not be found in the standards, but would likely have the same power limit as CDMA. We are not aware of the limit for 1xRTT, but it is transmitted over CDMA frequencies and should be subject to the same power limitations. The power density could fall off slower than the inverse square law assumed in the table above, but the inverse square law is generally used for such calculations in absence of an exact geometry specification.

Q3b is the power out put density fixed? If not please explain how the output can be adjusted up or down

A3b In theory, an AMI device power output can be changed both at initial deployment as well as dynamically. Specific device capability will vary from vendor to vendor as well as the technology upon which the AMI is based. At no point, however, can the power output exceed the maximum values as specified by Industry Canada.

Q3c What are the maximum possible out put densities of some typical meter readers?

A3c Maximum possible output density will vary depending on a specific meter and location of installation. Table A3a lists the maximum values for differing technologies.

Q3d Are the frequencies to be obtained by Industry Canada via a special requests

A3d Industry Canada requires licenses for the licensed frequency bands, a listing of which can be found on Industry Canada's website (http://spectrum.ic.gc.ca/tafl/tafindxe.html). Even the devices not intended for communication in the licensed frequency bands are regulated by Industry Canada for maximum power emission.

Q4: New Infrared technology is used for telecommunication purposes , since they

A4 FortisBC assumes that this question was intended to ask whether infrared technology can be used for AMI communications. FortisBC is not aware of any vendors currently offering this technology.

Q5: Of the in IR#1 Q13/ A13 and IR#2Q4 mentioned meter reading systems, please provide briefly –in layman's language- how they work.

A5 FortisBC assumes that this question references Karow IR No. 1 Q13 (Exhibit B-2) and Karow IR No. 2 Q4 above, and is asking for a brief description of how the AMI LAN communications systems work. In addition to the information given below, please also refer to the CPCN Application Appendix A page 44 (Exhibit B-1).

Wireless Network:

A wireless mesh AMI network is made up of a communications network in which there are at least two pathways of communication to each meter. The coverage provided by the meters working as a single network becomes a mesh cloud. Access to this mesh cloud is dependent on the meters working with each other to create an AMI LAN.

AMI technology built upon wireless mesh builds communication routes between meters in an organized manner. Data can "hop" between meters and to the collector point. The number of hops the data can transfer between is dependant on the specific AMI vendor.

Most AMI systems are "self-healing" in that if the usual pathway to the collector is unavailable, it will detect the next fastest route and use that instead. For example, if Meter A normally uses a neighboring Meter B to reach the collection point and Meter B is removed, Meter A will send out a signal to other neighboring meters and to the collector to determine the next fastest route. Once that route is located, Meter A will send its reading through that route until such time as Meter B becomes available again, This is important for redundancy and for the reliability of the AMI system.

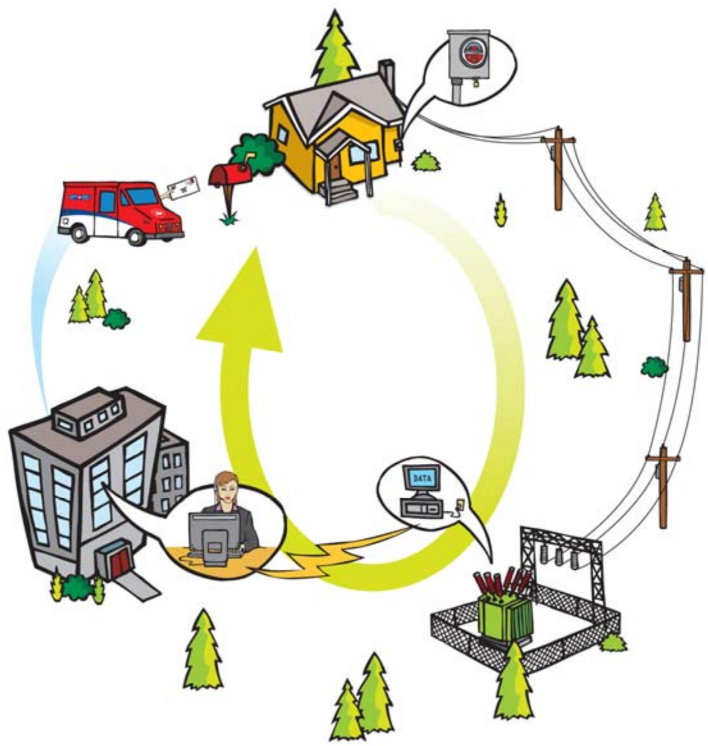
Figure 5A: Wireless Mesh Technology

Power Line Carrier

Power line communications systems operate by impressing a modulated carrier signal over the distribution power lines. The frequency of this transmission depends on the technology used and the wiring that the signal is being transmitted over. Since the power wiring system was originally intended for transmission of AC power, the power circuits may have only a limited ability to carry higher frequencies. This can be a limiting factor for each type of power line communications.

1 Once the signal reaches the distribution substation, it is transmitted back to the
2 office via a wide area network (WAN).

Figure 5B: PLC Technology



Q6: In densely residential areas, especially in multi-units Apartment complexes, please state – in layman's language - how the total/combined radiation output will behave (increase)at distances of 0.5 m, 1m, 5m and 25m radius area in cases of

1 meter readers
5 meter readers and
25 meter readers
aa) each of the above 0.5m apart mounted and read at the same time
bb) each of the above 10m apart mounted and read at the same time
cc) each of the above 25 m apart mounted and read at the same time

A6 By definition, the total radiation output is independent of the distance to the reader, and for multiple radiation sources increases with the number of sources present. The information provided is inadequate to calculate the total radiation output. One would need to know about the pattern of the sources (such as triangular, linear, square, etc.) to calculate the total number of readers present in a specific area.

It is misleading, however, to evaluate the total power radiation at a distance, as most power will not go in a specific direction. The quantity of concern is power intensity, which is the received power radiated per unit area. The calculation of power intensity is quite difficult and very much dependent on the location of the reader in or near the house. Nevertheless, a useful rule of thumb is that the power intensity drops by a factor of four for every doubling of the distance (inverse square law) as indicated in Table A3a.

Q7: Reference: B-2 Karow Q7 Fortis Response A17

Q17 Please state, if on special individual customer's demand the conventional metering system not to be changed over to the new AMI system, under what conditions may FortisBC allow so.

A17 No, the installation of AMI-enabled meters will not be optional. Allowing customers to remain on the legacy system would increase the cost to service those customers and limit the benefits offered by AMI.

If on medical advice an electro-sensitive resident <u>must</u> live without the new radio frequency radiation (RFR) emitting meter reader, at what cost or other conditions would FortisBC allow those customers to remain on the legacy system?

A7 FortisBC does not intend to have both conventional meters and AMI enabled meters in service beyond the implementation period. Please also refer to the response to Karow Q14 below.

Q8 Is FortisBC planning to apply for a separate CPCN for its most favored reading system by also including the closest alternative options in the application process? If not, why not. If not, how would ratepayers have a say as well in the choose of a system?

A8 No, FortisBC does not intend to file a new Application. Please see the responses to BCUC IR No. 1 Q13.1 and Q13.2 (Exhibit B-2) regarding further approvals. The opportunity for ratepayers and/or intervenors to participate and provide input in establishing the parameters by which an AMI system is chosen is through the regulatory process.

Q9 If the meter will be allowed to be mounted on the outside wall of a premises with a plastic/fibreglass cover will they be mounted on a metal wall-plate (which will prevent radiation going back into the house).

A9 It is not anticipated that there will be special mounting requirements for the AMI meters as they will be well within the range of health standards.

Q10 How often each day/week etc will the reader transmitter (although not chosen yet) typical be active and for how long each time (in seconds) at low, normal/average and at peak use periods?

A10 AMI systems vary from constantly transmitting a signal to transmitting once per day. The length of the transmission can also vary from continuous to several seconds.

Q11 Will the reader transmit data only when interrogated by an external master source requesting data? If not, please explain why not?

A11 The AMI enabled meter will not just transmit data when interrogated. The meters are programmed to automatically send readings at certain times without being polled by the AMI system. In addition, there are some AMI systems that are constantly transmitting as part of their communications infrastructure.

Q12 For the frequency range to be used with the meter reading system, what is the permitted maximum intensity in Canada? Please state source.

A12 Please refer to the response to Karow IR No. 2 Q3 above.

Q13 With regards of the Planck equation: e = hf , is it correct to say, that as the frequency gets higher, energy is increased, conversely, it takes less energy at higher frequencies to obtain higher power (Watt)?

A13 Radiated power is defined as energy radiated per unit time, and thus exactly the same number of Watts per second is required to get the same power output. The Planck's constant gives a correspondence between the energy per an emitted energy quanta (photon); the equation above implies that the number of photons emitted decreases with an increase in radiation frequency for the power source with a constant power output.

Q14 Does FortisBC realize that the Electrosentivity (ES) is more and more recognized as a medical problem worldwide, if ES one day will be recognized in Canada/BC, and assuming the new meter system's radio frequency radiation (RFR) is affecting ES people, how will FortisBC plan/be able then to deal with the mitigation of the RFR exposure in those cases?

A14 On issues relating to health and safety, FortisBC takes guidance from provincial, federal, and international agencies. FortisBC is not aware of any credible evidence to suggest that RFR levels generated by AMI devices would be the cause of any medical problems.

Q15 What is FortisBC position with regards of the last year's BioInitiative Report, http://www.bioinitiative.org/ , established by independent medical and scientific experts?

A15 The BioInitiative report was posted to an Internet website and was written by an *ad hoc* group of 14 scientists unaffiliated with any scientific agency to present their opinions in support of lower exposure standards for electric and magnetic fields (EMF). The report concluded that magnetic field exposure standards lower than those currently recommended by scientific agencies are warranted. This recommendation deviates substantially from recommendations made by Health Canada and other national and international scientific and health agencies because the authors of the BioInitiative report largely ignored basic scientific methods.

Q16 Is FortisBC aware, that in certain countries EMF/EMR guidelines' radiation exposure have been reduced to much lower levels than the WHO/ICNIRP and Health Canada EMF/EMR exposure guidelines?

A16 Exposure guidelines in Canada for radiofrequency fields are determined by Health Canada. Health Canada has not proposed guidelines for exposure to fields at extremely low frequencies. FortisBC has made no study of guidelines applied in other countries or the technical or political factors underlying those guidelines, although notes that the World Health Organization (WHO) discusses and describes guidelines implemented worldwide in its recent 2007 report. The WHO strongly recommends that countries adopt the ICNIRP guidelines, or use a scientifically sound framework for formulating any new guidelines.

Q17 With regards of RFR exposures within the scope of the subject project, how will FortisBC address/apply the precautionary principle other than just by referring to the FortisBC compliance of WHO/ICNIRP/Health Canada guidelines?

A17 FortisBC follows guidance from Health Canada, a Federal Government agency, with regard to radiofrequency fields. The precautionary principle is referenced frequently in Federal Government documents (for example, "A Canadian Perspective on the Precautionary Approach/Principle" which can be found at http://www.ec.gc.ca/econom/pp_e.htm).

Q18 In its application, FortisBC stated the safety of its reading-employees (i.e. vicious dogs), please state medical related costs incurred by such for each year over the past 10 years.

A18 Medical costs are generally covered by the BC Workers' Compensation Board ("WCB"), and paid for indirectly through premiums on a Company-wide basis. As meter readers are not a separate category of employees for WCB reports, FortisBC is unable to report on premium costs by year related specifically to meter reading incidents.

Q19 In its application, FortisBC stated cost saving factor as being a reason as well to change over to the new system. Please state the cost saving by not having any, more FortisBC employees reading the meters, independently from the new meter appliances and installation cost per month and per year over the next 10 years.

A19 Meter reading savings are reflected on line 26 of the Revenue Requirements Template as yearly savings. Table A19 shows the yearly savings as well as the average monthly savings for each of those years.

Table A19: Meter Reading Savings per Year and Per Month ($000s)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Yearly Savings	0	592	2,491	2,611	2,736	2,856	2,992	3,113	3,280	3,431
Monthly Savings	0	198	208	218	228	238	249	259	273	286

Q20 FortisBC reasons that the new meter reader system is saving cost.

a) how do FortisBC shareholders benefit from these saving costs in the short and long term?

b) how do rate payers benefit from these saving costs in the short and long tem??

A20 FortisBC has stated at page 4 of the Application (lines 9 – 12, Exhibit B-1) that the full amount of operational savings will be used to reduce revenue requirements, therefore all of the benefits from cost savings will accrue to customers, and not to shareholders. Further information was provided in response to BCUC IR No. 1 Q1.1 (Exhibit B-2). In addition, any revenues generated by third party use of the AMI will also benefit customers, as described in response to BCUC IR No. 2 Q4.4.

Q21 Assuming new meter readers RFR have been proved to be related/associated/attributed to residents' medical problem, in case of claims, does FortisBC have third party insurance?

a. If so, please state insurance company and relevant insurance policy section/s that do state that EMF/EMR related claims are covered.

b. If not, is FortisBC aware that in recent years Insurance policies have been amended that EMF/EMR related claims are not covered? In that case, what does FortisBC suggest how claims should be recovered by the affected residents?

A21 FortisBC carries property and liability insurance. Please also refer to Karow IR No. 2 Q14 above.

Project No. 3698493: Advanced Metering Infrastructure (AMI) Project
Requestor Name: Horizon Technologies Inc. (Mr. Ludo Bertsch)
Information Request No: 2
To: FortisBC Inc.
Request Date: March 6, 2008
Response Date: March 19, 2008

1.0 References: Exhibit B-2, BCUC A1.2 and B-1 Table 7.1:

FortisBC states in A1.2 that "*Following implementation, FortisBC will be able to provide customers access to their usage data and electricity costs in some manner such as a secure internet logon.*" Table 7.1 lists "*Interface to Customer Web Access*" within "*AMI Functions and Features*".

Q1.1 Please confirm that the "customers access" noted in A1.2 and the AMI Feature "Interface to Customer Web Access" of Table 7.1 reference the same feature. If not, please explain.

A1.1 Confirmed.

Q1.2 Please specify the maximum time lag from consumption of energy to its accessibility on the Internet that would be acceptable. Will this function be included in table 7.1; if not, why not?

A1.2 The maximum time lag from consumption of energy to accessibility on the internet would occur if daily meter readings were transmitted via PLC. With daily readings, there is a maximum lag of 24 hours between consumption and a meter reading. Once the reading is obtained, it will take a maximum of 24 hours for the data to be processed by the MDMR and made accessible on the internet for a total of 48 hours from consumption to display on the internet. The maximum allowable time lag will be specified in the RFP.

Q1.3 Will the "usage data and electricity costs" be available in an open standard form useful for third party developers? If not, why not? Will this feature be specified as a requirement for AMI vendors and added to Table 7.1? If not, why not?

A1.3 Information will be provided in some manner to customers on their specific usage data and electricity costs (most likely through the internet). The availability of this information in an open standard will be considered providing this does not add additional cost to the project and provided that the security is in place to ensure the confidentiality of customer data.

2.0 References: Exhibit B-2, BCUC A1.2 and B-1 Table 7.1:

FortisBC states in A1.2 that "*The real-time display of system consumption or electricity prices could be provided to customers over the internet today.*" [emphasis added]. Table 7.1 lists "*AMI Functions and Features*".

Q2.1 Please clarify if FortisBC is committing to supplying this feature as part of this CPCN application. If not, please specify how such "FortisBC intends to provide customers access to consumption information to raise awareness and provide tools necessary to conserve energy".

A2.1 The real-time display of overall system consumption and the purchase price of electricity being experienced by the utility is not within the scope of the AMI Project and therefore is not listed in Table 7.1.

FortisBC is committing to provide customers with detail on their individual consumption patterns. This information is one of the tools necessary to help customers conserve energy.

Q2.2 Please specify how this feature is referenced in AMI Functions and Features Table 7.1.

A2.2 Access for customers to their consumption data and the price that they are paying for electricity is covered in Table 7.1 as "Interface to Customer Web Access".

3.0 Reference: Exhibit B-2, BCUC A5.1:

Q3.1 Only a general statement relating to costs was supplied by FortisBC. Please indicate in dollar value (say, for the last 5 years) how these costs have evolved compared to drive-by technology.

A3.1 Please refer to the response to BCUC IR No. 2, Q3.1.

4.0 Reference: Exhibit B-2, BCOAPO A10.3:

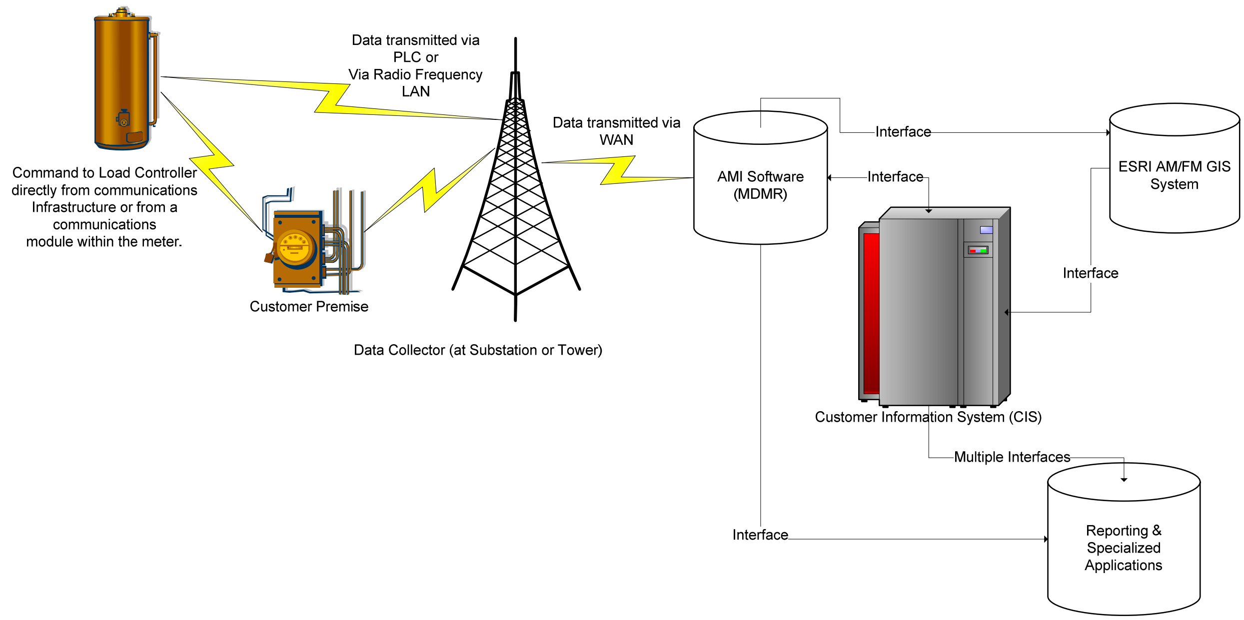
Q4.1 FortisBC indicates the "AMI infrastructure would allow for a program to place load-controlling devices onto appliances in customers' premises" yet would not work with existing meters. Please elaborate on specifically how the AMI infrastructure enables this. Please use a diagram to explain.

A4.1 As a point of clarification, this answer refers to "existing meters and infrastructure" (emphasis added). Load controlling devices cannot be controlled through the existing meters and/or through existing communications infrastructure.

Depending on the AMI technology selected, load controlling devices are controlled through the AMI-enabled meter and/or directly through the LAN communications infrastructure.

Please see Figure 4.1 below which illustrates these options.

Figure 4.1: AMI Communications Network



5.0 Reference: Exhibit B-2, BCOAPO A12.1:

Q5.1 FortisBC indicates it "has reviewed documents from several other utilities". Please list the utilities. Please list (by BCUC application and document number) or include the specific documents relating to BC Hydro.

A5.1 FortisBC has reviewed documents from utilities operating in jurisdictions other than BC including FortisAlberta, Chatham Kent Hydro, Pacific Gas and Electric Company, Hydro One, TXU Energy (Texas) and Avista Energy.

6.0 Reference: Exhibit B-2, BCOAPO A16.2:

Q6.1 FortisBC indicates at least thirty days of readings will be required. Please indicate if this feature will be added to Table 7.1. If readings are taken every half hour or quarter hour, will this requirement remain?

A6.1 If readings were taken every half hour or quarter hour instead of daily, the number of days that can be stored on a meter may decrease as there is a finite amount of memory within the meter.

7.0 Reference: Exhibit B-2, Mr. Hans Karow A13:

Q7.1 Power Line Carrier (PLC) is noted as an option for the LAN. Please indicate the approximate frequency ranges used.

A7.1 PLC uses signals in the 40 - 490 kHz range.

Q7.2 Please clarify if PLC includes Broadband over Powerline (BPL) technologies. If not, please indicate why this was not considered.

A7.2 FortisBC considers Broadband over Powerline (BPL) to be a PLC technology and will consider vendors offering AMI systems based on BPL technology.

8.0 Reference: Exhibit B-2, Mr. Alan Wait A10 and B-1 Table 7.1:

Q8.1 FortisBC indicated that a common platform for communications equipment and proprietary communications protocols would be “considered within the scope of the RFP”. Please indicated the feature/function within Table 7.1 to which this refers. If not listed, please confirm that the feature will be included into the table.

A8.1 The answer provided in response to Wait IR No. 1 Q10 (Exhibit B-2) was not intended to convey that FortisBC will not consider technologies with proprietary communications protocols for the LAN. There are benefits and disadvantages of both public and proprietary communications protocols. During the RFP process, vendors will be required to describe in detail the communications platform utilized by their AMI technology so that FortisBC can evaluate the flexibility of their system.

The communications protocol used by the AMI technology relates to the design technology itself and not to one specific function or feature of the AMI system.

Q8.2 Will any other communication-related features or functions (such as throughput, error rates etc.) be included in the Table 7.1. If so, please list them and indicate whether “required” or “optional”. If not, please indicate why not?

A8.2 FortisBC does not expect any other communication related features and functions to be included in the functional requirements listed in Table 7.1. However, there will be technical requirements that will be developed through the creation of the RFP document should the AMI project be approved. The specifications of the Ontario Smart Metering initiative and FortisAlberta’s RFP will be utilized as references in the creation of FortisBC’s technical RFP requirements.

Within the RFP document, vendors will be required to determine the number of communications devices required based on FortisBC's service area as well as retrieve at least 98 percent of reads from all meters daily.

Q8.3 Please clarify which functions/features of table 7.1 are for meter manufacturers or communications provider or both?

A8.3 As stated in response to BCUC IR No. 1 Q25.2 (Exhibit B-2), FortisBC expects that the vendor portions of the AMI Project will be integrated into one turnkey vendor solution. As such, the functions and features listed in Table 7.1 have not been separated between those that are for meter manufacturers versus communications providers. The vendor who is responding to the RFP will be responsible for ensuring all requirements are met independent of which component within the AMI system is providing that feature.

9.0 Reference: Exhibit B-2, Mr. Alan Wait A11 and B-1 Table 7.1:

Q9.1 FortisBC indicated reporting delays for PLC technologies. Please specify delays for all other technologies. Please indicate if that feature will be included in table 7.1. If not, please indicate why not.

A9.1 Most RF technologies experience only a slight delay (within 15 minutes of the reading time). As discussed in response to Horizon IR No. 2 Q8.2 above, technical requirements will be developed through the creation of the RFP document should the AMI Project be approved.

FortisBC expects to require at a minimum that the daily reading be delivered to the MDMR within 12 hours of the time the reading was taken at the meter.