Dennis Swanson
Director, Regulatory Affairs

FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna BC V1Y 7V7
Ph: (250) 717-0890
Fax: 1-866-335-6295
dennis.swanson@fortisbc.com
www.fortisbc.com

May 22, 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. 3 from the BC Utilities Commission, BCOAPO et al., Horizon Technologies, Mr. Hans Karow. Twenty copies will be couriered to the Commission.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

cc: Registered Intervenors

36.0 Reference: Document Submissions

Q36.1 As part of their response to this round of information requests, would FortisBC please submit electronic copies (PDF format) of all referenced documents in this information request on a CD?

A36.1 A CD containing the following documents has been included with this round of Information Request responses:

- "Advanced Metering Infrastructure: What Regulators Need to Know About Its Value to Residential Customers", Nancy Brockway, February 13, 2008 (reference BCUC IR No. 3 Q37.1)
- FERC Staff Report on Demand Response and Advanced Metering, David Kathan, FERC, October 10, 2006 (Reference BCUC IR No. 3 Q38.4.2, Q56.1)
- California's Next Generation of Load Management Standards, prepared for: California Energy Commission, the Brattle Group, May 2007 (Reference BCUC IR No. 3 Q38.4.3)
- Virginia State Corporation Commission Case No. PUE-2006-00003 Final Order, July 18, 2006 (Reference BCUC IR No. 3 Q38.5.3)
- Ontario AMI Functional Specification – Version 2, July 2007 (Reference BCUC IR No. 3 Q46.2)
- FERC, 2007 Assessment of Demand Response and Advanced Metering, September 2007 (Reference BCUC IR No. 3 Q46.9)
- Ontario Energy Board, 2007 EDR Smart Meter Rate Calculation Model (Reference BCUC IR No. 3 Q49.0)
- Essential Services Commission, Advanced Metering Infrastructure Review: Final Framework and Approach Volume 1 Guidance Paper, December 2007 (Reference BCUC IR No. 3 Q49.0)
- FERC, 2006 Assessment of Demand Response and Advanced Metering, August 2006 (Reference BCUC IR No. 3 Q49.0)
- Supplement to Phase I AMI Implementation Status Report Case No. IPC- 06-01 (Reference BCUC IR No. 3 Q49.0)

- National Association of Regulatory Utility Commissioners, Sixteen State Regulators Join NARUC-FERC Smart Grid Collaborative, March 31, 2008 Release (Reference BCUC IR No. 3 Q51.5)
- Home Area Network Workshop, EnerNex Corporation, Grant Gilchrist, 2008 (Reference BCUC IR No. 3 Q59.5)

37.0 Reference: Best Interest to Customers

Exhibit B-6, p. 4

National Regulatory Research Institute

Q37.1 Please submit a copy of National Regulatory Research Institute document "Advanced Metering Infrastructure: What Regulators Need to Know About Its Value to Residential Customers" by Nancy Broadway, February 13, 2008.

A37.1 A copy of the requested document is contained on the CD included with this round of Information Requests. A copy of this document is also included as BCUC Appendix 37.1.

Q37.1.1 Would FortisBC please provide comment on the document?

A37.1.1 The referenced document provides a useful discussion of AMI implementation and the quantification of demand response benefits that may be achieved with AMI technologies. Of interest is the discussion in regards to three pricing pilots being used to attempt to quantify demand response ("DR") benefits. Those pilots are the California Statewide Pricing Pilot; the Commonwealth Edison/Community Energy Cooperative Energy-Smart Pricing Plan; and the Ontario Smart Price Pilot.

Several key findings within this document are:

- AMI is one way for a utility to offer time based rates and DR programs, but not the only way;

- AMI must be used and useful in the service of its customers, and it also must be more cost effective than all reasonable alternatives that exist for accomplishing the same functions or achieving the same benefits;
- Three major categories of AMI savings include operational savings, resource cost savings and service improvements. There is currently much debate over the extent to which residential customers can or will respond to such time-varying pricing;
- The biggest DR savings were realized by customers on critical peak pricing with direct load control;
- Response to these programs was better when customers had technological tools available to assist them in monitoring and controlling their usage;
- Although the participants in the studies were roughly representative of residential customers, self selection into the pilots skewed the participants toward higher use, higher income customers;
- In general, lower income customers reduced their loads by a higher percentage of their overall consumption than higher use customers, and as a result, had the highest proportionate bill reductions overall;
- The pilots do not provide a basis for estimating the sustainability of these conservation behaviors and savings over the long term;
- The pilots do not provide a basis for estimating the percentage of customers that would participate if the program was voluntary; and

- The pilots do not provide a reasonable estimate of bill impacts across different subsets of residential customers because the rate design issues have not been clearly identified and dealt with.

Although these pilots indicate that significant DR benefits may be achievable, FortisBC agrees with the document's conclusion that it is difficult to quantify those benefits and to predict customer behaviour and bill impacts from pilots alone.

The level of customer support required to change consumption behaviour is a key reason that FortisBC intends to use a staged approach to the development of DR, DSM and rate strategies. After implementation of the AMI Project, the hourly data gathered will allow FortisBC to better understand customers and model DR scenarios so that the impact to all classes of customers can be quantified. The infrastructure provided by the amended AMI system will also allow more flexibility in implementing effective DR programs, including the information and control options that customers will require.

38.0 Reference: Energy Policy
Exhibit B-6, p. 4
AMI and DR/DSM Integration

FortisBC states that "These amendments support several policy actions within the BC Energy Plan including conservation requirements, cost effective DSM opportunities and the exploration of new rate structures that encourage energy efficiency and conservation."

Q38.1 Would FortisBC agree that the amended AMI Application is a critical element or a first step required to achieve demand response savings? If not, please explain.

A38.1 Throughout IR No. 3, there are a number of references to demand response (DR) and demand-side management (DSM). FortisBC uses the following definition of demand response: "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 peak times."

Demand-side management refers to "the reduction of total electric usage by end-use customers in response to changes in the price of electricity over time or with the amount of consumption, or to incentive payments designed to induce lower electricity use."

DR savings can be achieved with technologies other than AMI. An example of this is load control devices which are controlled through paging technologies. For this reason, AMI should not be considered the only means to achieve demand response savings.

However, FortisBC believes that the implementation of AMI is a first step to supporting future conservation targets for two reasons. First, the Amended

Application provides the infrastructure to more easily implement flexible demand response programs in the future by providing a common communications infrastructure for both operational needs and DSM programs. Second, that the hourly data provided by the AMI and VEE equipped MDM systems will allow a more accurate and cost effective analysis of rate options and their impact on customer classes and conservation targets.

Q38.2 Would FortisBC experience a loss of revenue as a result of the implementation of AMI from either DR or DSM?

A38.2 If the implementation of DR or DSM resulted in a reduction in electricity use, and all else was equal (including rates), then FortisBC would experience a loss of revenue. Revenue loss would depend on several factors, including the magnitude of customer response to DR or DSM measures, as well as any changes in rates or tariff structure.

Q38.3 Would FortisBC also experience a corresponding reduction in operating or other costs as a result of implementing AMI?

A38.3 It is possible that power purchases would be reduced if the implementation of DR or DSM resulted in a reduction in electricity use. It is also possible that future load-driven capital expenditures could be delayed.

The operating cost reduction and capital savings expected without further investment in DR and DSM as a result of the Amended AMI implementation can be found in Section 4.1.1 (Operating Savings) and Section 6.3 (Avoided Future Capital Costs) (Exhibit B-1).

Q38.4 Does FortisBC have a demand response management plan that allows for the integration of AMI?

A38.4 FortisBC does not have a formal demand response management plan although there are emergency voltage reduction schemes in place that could be used to reduce demand in response to very high market exposures. These schemes could be optimized with the use of AMI, provided that the endpoints supported voltage readings (voltage reading is an optional functional requirement in the Amended Application, but many endpoint vendors include this feature as standard in their endpoints).

Q38.4.1 What are the FortisBC planned DR objectives in introducing AMI?

A38.4.1 FortisBC intends to utilize the AMI system after implementation to investigate a variety of DR and DSM tools, including time-based rates, automated load control and in-home display of energy use data.

The functionality provided by the AMI system includes support for in-home displays, hourly readings and load control, making these studies more effective and less costly than they would be without the advanced metering infrastructure.

Q38.4.2 Does FortisBC agree with a FERC statement[1] that demand response capability represents between 3% and 7% of peak demand in most regions? If not, please explain.

A38.4.2 Yes, FortisBC agrees that the range indicated above has been the experience and/or prediction in most regions represented in the FERC study.

Q38.4.3 California[2] has estimated the potential values of demand response. Has FortisBC estimated the potential value of demand

[1] FERC Staff Report on Demand Response and Advanced Metering, David Kathan, FERC, October 10, 2006
[2] California's Next Generation of Load Management Standards, prepared for: California Energy Commission, prepared by: the Brattle Group, May 2007

response within their service area? If not, please explain?

A38.4.3 FortisBC performed a conservation potential study most recently in 2005, but has not estimated the potential value of demand response. Comprehensive demand response studies are costly to perform and typically require some type of communications infrastructure to monitor electric usage, provide additional information to customers and implement load control. The BC Hydro Conservation Research Initiative currently underway, for example, utilizes an AMI infrastructure. As described in the response to BCUC IR No. 3 Q38.4.1, FortisBC believes that AMI-enabled DR and DSM programs are best designed after the implementation of AMI, since customer response is more easily studied and quantified.

Q38.5 As FortisBC is a utility that purchases wholesale power through long-term contracts or other arrangements,

Q38.5.1 Does FortisBC have the option of purchasing time-based cost varying wholesale power?

A38.5.1 Yes, FortisBC has access to the real-time wholesale power markets.

Q38.5.2 How would FortisBC plan to offer time-based demand savings to their customers?

A38.5.2 The benefits of demand savings based on timing of consumption, if implemented in the future, should be realized by the customers who contribute to the savings. Time-based rates such as Time-of-Use or Critical Peak Pricing rates would achieve this goal. In addition, the Company’s Revenue Requirements matches revenues and expenses annually, therefore to the extent that demand savings are realized, customer rates will reflect those savings.

Q38.5.3 Would FortisBC please submit the document – Va.S.C.C., Case PUE-2006-00003, July 18, 2006, at 251 PUR 4th 350?

A38.5.3 The document requested is a Final Order on behalf of the Virginia State Corporation Commission rejecting the implementation of a new federal time-based metering communications standard requiring utilities to offer time-of-use rates and “smart metering” capability to each customer class as directed by the U.S. Congress in the 2005 Energy Policy Act. The requested document is attached as BCUC Attachment A38.5.3.

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, JULY 18, 2006

COMMONWEALTH OF VIRGINIA ex rel.

STATE CORPORATION COMMISSION CASE NO. PUE-2006-00003

Ex Parte: In the matter of considering
§ 1252 of the Energy Policy Act of 2005

FINAL ORDER

On February 6, 2006, the State Corporation Commission ("Commission") established a proceeding to consider for implementation in the Commonwealth the new federal standard under the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601 et seq. ("PURPA"), that, if adopted, would require utilities to offer time-of-use rates and attendant "smart metering" capability to each of its customer classes. Such standard was enacted by the U.S. Congress in § 1252 of the Energy Policy Act of 2005, P.L. 109-58, 119 Stat. 594 (the "Energy Policy Act"). As noted in the Order Establishing Proceeding, § 111(a) of PURPA requires each state regulatory authority, with respect to each electric utility for which it has ratemaking authority, to consider certain federal standards for electric utilities established by PURPA. Each such state regulatory authority is required to determine whether or not it is appropriate, to the extent consistent with otherwise applicable state law, to implement these standards.[1]

Section 1252(a) of the Energy Policy Act amends § 111(d) of PURPA, 16 U.S.C. 2621(d), by adding the following standard for consideration:

> (14) TIME-BASED METERING AND COMMUNICATIONS –
> (A) Not later than 18 months after the date of enactment of [this standard], each electric utility shall offer each of its customer classes, and provide individual customers upon

[1] 16 U.S.C. § 2621.

customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

(B) The types of time-based rate schedules that may be offered under the schedule referred to in subparagraph (A) include, among others -

(i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;

(ii) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;

(iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and

(iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

(C) Each electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.

. . . .

> (E) In a [s]tate that permits third-party marketers to sell electric energy to retail electric consumers, such consumers shall be entitled to receive the same time-based metering and communications device and service as a retail electric consumer of the electric utility.
>
> (F) [E]ach [s]tate regulatory authority shall not later than 18 months after the date of enactment of this [standard] conduct an investigation . . . and issue a decision whether it is appropriate to implement the standards set out in subparagraphs (A) and (C).

In the February 6, 2006, Order Establishing Proceeding, the Commission noted that, pursuant to § 1252 (i) of the Energy Policy Act, the Commission is not obligated to consider the time-based metering and communications standard where certain prior state action has occurred. The Commission invited interested persons to comment on the following issues: (1) whether any prior state action has occurred such that the standard or a comparable one has already been implemented or considered in the Commonwealth; (2) whether the Commission has the authority to consider the standard and whether the implementation of such standard would be consistent with otherwise applicable Virginia law; (3) whether electric utilities over which the Commission has ratemaking authority should be required to offer each of its customer classes and to provide customers upon request a time-based rate schedule that will enable the customer to manage energy use and cost through advanced metering and communications technology; (4) whether electric utilities over which the Commission has ratemaking authority should be required to provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate; (5) whether customers buying electricity from third-parties should be entitled to the same time-based metering and communications device and service as a retail electric customer of the electric utility; and (6) if advocating implementing the time-based metering and communications standard, how such standard would best be implemented.

Comments were submitted by Mr. John F. Angle, Mr. Stephen H. Brown, Mr. Alden M. Hathaway, Ms. Debra A. Jacobson, Mr. Michel A. King, Appalachian Power Company, the Demand Response and Advance Metering Coalition, Delmarva Power, Potomac Edison Company, Itron, Inc., the Maryland-District of Columbia-Virginia Solar Energy Industries Association, Virginia Electric and Power Company, and the Virginia Electric Distribution Cooperatives.[2] The Staff also filed comments summarizing the comments filed by interested persons, responding to certain of those comments, and presenting the Staff's findings and recommendations.

The comments from interested electric customers and others advocating the federal standard generally indicated that time-based metering and communications are appropriate and desirable and, therefore, that the Commission should require the utilities to provide all classes of customers, including those buying electricity from third-party suppliers, with the opportunity to employ time-based metering and be on time-based rate schedules. Such comments also advocated the ability to both time-of-use meter and net-meter, which is currently prohibited by the Regulations Governing Net Energy Metering Rules, 20 VAC 5-315-10 et seq.

The investor owned utilities indicated that they already offer time-of-use metering and rates to certain classes of customers and that customers may request an interval meter. These utilities also noted that those who purchase electricity from third parties are entitled to the same

[2] Collectively, A & N Electric Cooperative, BARC Electric Cooperative, Central Virginia Electric Cooperative, Community Electric Cooperative, Craig-Botetourt Electric Cooperative, Mecklenburg Electric Cooperative, Northern Neck Electric Cooperative, Northern Virginia Electric Cooperative, Prince George Electric Cooperative, Rappahannock Electric Cooperative, Shenandoah Valley Electric Cooperative, Southside Electric Cooperative, and the Virginia, Maryland & Delaware Association of Electric Cooperatives ("Cooperatives").

time-based metering and communications devices as retail utility customers. Several of the utilities submitted that there is no real demand for time-based metering options and limited participation in such offerings as are already available. The comments also submitted that the utilities must have flexibility to define and design time-based rate schedules and should be able to recover any costs associated with time-based metering. Further, the comments raised the issue of existing rate caps.

The Cooperatives noted, among other things, that they purchase their power through wholesale supplier contracts that presently offer no time-based pricing and argued that the Cooperatives should be permitted to decide whether to offer time-based metering data and equipment based on the market.

Based on the comments filed, the Staff submitted that the federal time-based metering and communications standard requiring utilities to offer time-of-use rates and smart metering capability to each of its customer classes should not be implemented at this time. The Staff noted the current tariff offerings by the investor owned utilities and that both utility customers and those who buy from third parties may request a time-based metering and communications device. The Staff noted the circumstances under which the cooperatives purchase electricity. The Staff also indicated, however, that implementation of a program requiring utilities to offer time-based rates and system-wide deployment of smart metering and communications technology should not be completely dismissed pending the expiration of capped rates and the outcome of electric restructuring pursuant to the Virginia Electric Utility Restructuring Act, Chapter 23 (§ 56-576 et seq.) of Title 56 of the Code of Virginia ("Restructuring Act"). The Staff submits that such a program may provide customers with protection against more volatile rates and possible increases to customer bills.

NOW THE COMMISSION, upon consideration of the comments filed herein and the applicable law, finds that the federal time-based metering and communications standard established by § 1252 of the Energy Policy Act should not be implemented in the Commonwealth at this time.

The Commission is not convinced that adoption of this standard is, at this juncture, in the public interest. The investor owned utilities already provide certain opportunities for customers to take service pursuant to time-of-use rate schedules. Even without any limitations that the Restructuring Act may impose with respect to requiring utilities to provide time-based rate schedules, we find that utilities or third party service providers should not at present be required to provide each customer class a time-based rate schedule or a time-based meter capable of enabling a customer to receive such rate. There appears to be minimal customer demand for such schedules, even for those that currently exist. Customers may not be capable of or willing to, among other things, vary demand and usage in response to changes in prices based on specific time periods, manage costs by shifting usage to lower cost or off-peak time periods, or reducing consumption. As any competitive market develops, it may be that requiring utilities to offer time-based rates and provide time-based meters and communications to all customers would be appropriate. However, we decline to implement such requirement in the instant proceeding.

Accordingly, IT IS ORDERED THAT:

(1) This proceeding is hereby closed.

(2) There being nothing further to come before the Commission in this proceeding, this case shall be removed from the docket and the papers transferred to the file for ended causes.

AN ATTESTED COPY hereof shall be sent by the Clerk of the Commission to all persons on the official Service List in this matter. The Service List is available from the Clerk of the State Corporation Commission, c/o Document Control Center, 1300 East Main Street, First Floor, Tyler Building, Richmond, Virginia 23219.

Q38.5.3.1 Would FortisBC please explain how they differ from the Cooperatives in their power purchase agreements?

A38.5.3.1 The Cooperatives purchase all their power through wholesale supplier contracts that offer no direct time-based pricing. However, the Cooperatives do have exposure to market prices through fuel surcharges. Recent large increases in these surcharges are driving them to adopt AMI as a conservation measure.

FortisBC does not rely on power supply contracts shortfall as the Cooperatives do. In addition, FortisBC major power supply contracts do not have fuel surcharge provisions. However, FortisBC does have direct exposure to market costs at this time due to the current reliance on the market to meet a portion of peak demand.

Q38.6 Please provide a chart or graph that shows FortisBC's marginal cost of energy as a function of system demand. If the marginal cost varies with other factors, such as season, please provide the relevant graphs/charts. Please ensure that demand levels up to those expected by the end of the planning horizon are covered, and include CO_2 offset costs (and volume in tonnes) where relevant.

A38.6 FortisBC does not have the data readily available to calculate the marginal cost of energy as a function of system demand and season. Furthermore, although the Company currently has a large capacity shortfall, this is not expected to be the case in the future as the Company shifts to greater self-sufficiency. The marginal cost of electricity for FortisBC is best represented by the cost of new capacity expressed in terms of levelized unit cost. Levelized unit cost is the unit cost of production that would result in the same net present value of revenue requirements as if the actual cost of production were collected over the term being examined. In this analysis, levelized unit costs were calculated by dividing the net present value of revenue requirements of the project being analyzed by the net present value of capacity over a 25 year term. Costs are in 2008 dollars.

The analysis assumes that the top 20 MW of load is supplied by either a $28.5 million Simple Cycle Combustion Turbine or a $60 million Pumped Hydro Storage system. This places the Company's levelized unit cost of capacity at between $165,000 and $245,000 per MW, discounted at 10 percent. Since there is only approximately 2 GWh of energy associated with the top 20 MW of capacity, the marginal cost of capacity is an order of magnitude more important than the marginal cost of the energy. Note that the capacity costs include the appropriate carbon based costs as per the proposed BC Carbon Tax (escalating to $30 per metric tonne by 2012). Therefore, the benefits of any sort of load-shifting and peak shaving project are largely in the capacity savings at this time, as stated in the range of $165,000 to $245,000 per MW (levelized unit cost).

Q38.7 If the marginal cost of energy provided in response to the previous question is heavily influenced by energy supply contracts that may not reflect the true (underlying) marginal cost of energy, please estimate those underlying marginal costs by estimating the generation mix (base load, mid-range, and peaking plants) that would be required to meet FortisBC's expected future demand.

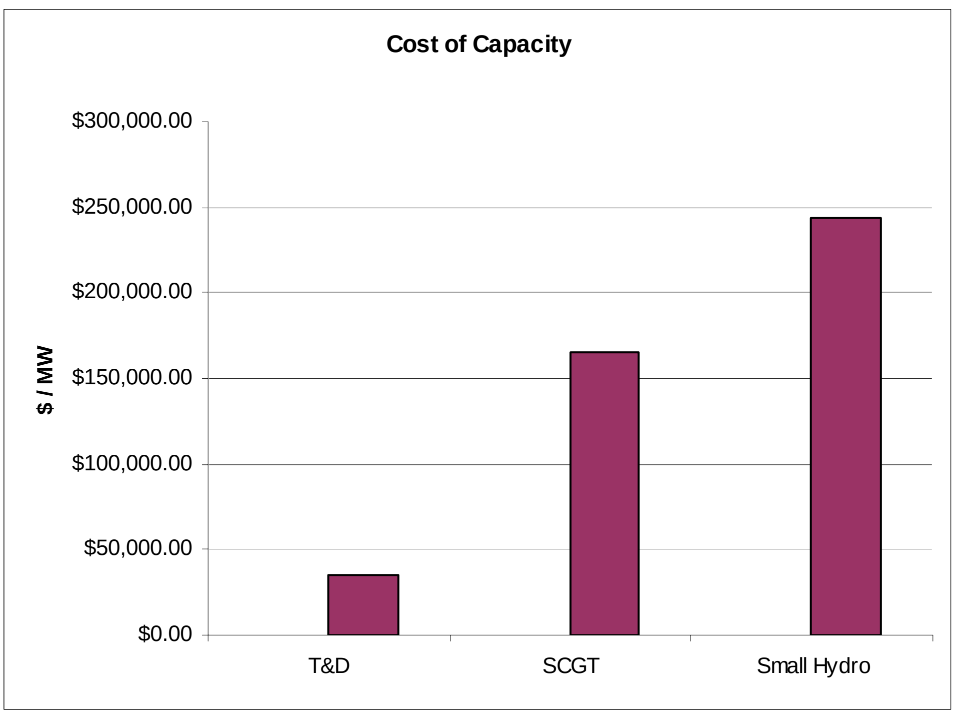
A38.7 The marginal cost of energy is not expected to be heavily influenced by energy supply contracts.

Q38.8 Please provide a chart or graph that shows FortisBC's assumed incremental cost of capacity for generation (various asset types), transmission wires, and distribution wires. If the values assumed for rate-

making purposes are different than the actual values that would be expected for the development of physical resources, please provide both values.

A38.8 In addition to the marginal cost of generation provided in the answer to BCUC IR No. 3 Q38.6, there are marginal transmission and distribution costs of $35,600 per MW (the avoided cost figure used in FortisBC DSM filings). This results in a total incremental cost of capacity of between $200,600 and $280,600 per MW.

Please see below for a graphical representation of the total incremental cost of capacity:



39.0 Reference: Energy Policy
Exhibit B-6, p. 4
Demand Response Benefits

Q39.1 Would FortisBC expect to experience net positive benefits from either demand response or societal impacts as a result of time of use rate structures and the AMI project in the future? Please explain.

A39.1 Please see the response to BCUC IR No. 3 Q38.4.1 and Horizon IR No. 3 Q3.5.

Q39.2 If FortisBC was to experience net positive benefits from the AMI project through demand response or societal impacts,

Q39.2.1 How would these benefits be quantified?

A39.2.1 The benefits from demand response would be quantified by observed reductions in electricity use at peak times. Societal benefits such as GHG emission reductions could result from reduced energy purchases or delayed capital construction.

Q39.2.2 How would these benefits be distributed to the ratepayers?

A39.2.2 Please see the response to BCUC IR No. 3 Q38.5.2 regarding the benefits of demand response savings. Generally, the benefits of societal impacts would be realized by all ratepayers (and may not be limited to FortisBC ratepayers).

Q39.3 Does FortisBC have sufficient information to establish a demand response baseline for monitoring the effectiveness of the proposed AMI project?

A39.3 FortisBC does not have sufficient information to establish a demand response baseline. Ideally, a demand response baseline would include hourly demand readings from a statistically significant number of customers in all customer classes. Hourly data is currently only available for a small number of industrial customers. Following AMI implementation, this information will be readily available for all customers.

Q39.3.1 Would FortisBC agree to implement a demand response capability program that would produce an additional 5% reduction of the 2007 Peak Demand to be re-evaluated after two years of AMI operation?

A39.3.1 FortisBC intends to study a variety of DR and DSM tools after the implementation of AMI as described in the response to BCUC IR No. 3 Q38.4.1. Design and implementation of effective DR and DSM programs is likely to require additional analysis, expenditures, and the implementation of time-based rates. Due to the time required to complete these studies, gain expenditure authorization, and approval for related time-based rates, FortisBC is unable to commit to a specific timing of reductions in peak demand. Please also refer to Horizon IR No. 3 Q3.5.

Q39.3.1.1 As the Ontario Program also had as a goal of a 5% reduction of the forecasted peak demand by 2007, would FortisBC comment on whether or not the Ontario target of a 5% reduction of the forecasted peak demand was achieved?

A39.3.1.1 The April 2008 report from the Ontario Power Authority entitled “A Progress Report on Electricity Conservation 2007” reports that the province achieved approximately 600 MW of summer peak demand savings as compared to a target of 1350 MW. 317 MW of the peak demand savings were achieved from two demand response programs, both in the industrial sector. The report anticipates that once the remaining 75 percent of meters are installed, and time-based rates are introduced, the stated demand savings goals will be more likely to be achieved.

Q39.4 Are there any additional cost savings, such as generation capacity and energy costs, and transmission and distribution capacity that FortisBC can obtain by using AMI to support time-varying prices, thus lowering system resource costs that remain unaccounted for?

A39.4 If time-varying prices result in overall system demand savings, there may be additional cost savings related to future infrastructure costs and energy purchases. These savings should be factored into any decision regarding the implementation and cost of demand response programs.

Q39.5 Does FortisBC expect that AMI would provide benefits for feeder phase balancing and/or for load transfers among substations to reduce station peak demands and losses?

A39.5 Yes, FortisBC believes that AMI will provide benefits for feeder phase balancing and/or for load transfers among substations to reduce station peak demands and losses. The benefits are difficult to quantify and were therefore included as soft benefits, “Enhanced System Modeling”, in the Original Application (Exhibit B-1, page 17).

40.0 Reference: VEE

Exhibit B-6, 3. Hourly Reading, p. 8

Missing Readings

FortisBC states "Reduced Estimates Due to Missed Reads: Estimated bills are often a source of customer dissatisfaction. In the FortisBC second quarter 2007 Customer Satisfaction Survey, the percentage of customers indicating their satisfaction with the accuracy of metering reading as 9 out of 10 or higher (10 being most satisfied) was 57 percent. Despite reading over 97 percent of meters when scheduled in 2006, approximately 17,400 scheduled meter reads were still estimated due to various reasons (staffing, access, severe weather conditions)" (Exhibit B-1, pp.17-18).

FortisBC states the reason for the Validation, Estimating and Editing (VVE) is to provide estimates for missing hourly readings and that the proposed 98% read success rate will still produce 50,000 gaps or missing readings that need to be estimated.

Q40.1 What are the read success rates and percentage of estimated readings in: (a) existing AMI systems that FortisBC is familiar with; and (b) being promoted by AMI vendors?

A40.1 In both cases, the read success rates range from 95 percent to 99.9 percent.

Q40.2 Would FortisBC please explain how VEE fills in these missing readings?

A40.2 Most MDMR systems equipped with VEE have estimating algorithms that can be customized to reflect the utility's business processes. If the gap is only a one hour gap, the estimating algorithm may take a simple average of the hour before and after the gap. If a full day's worth of readings is missing, the algorithm may estimate readings based on factors such as previous customer consumption, ambient temperature and system outages. These details would be coordinated with the MDMR vendor and tested during the installation phase of the project.

Q40.3 Would FortisBC please explain why this is still considered as a customer benefit considering the high degree of accuracy of the existing meters and the current level of customer satisfaction?

A40.3 More accurate readings and increased customer satisfaction ratings are expected as a result of the AMI project as a whole rather than one component of the project such as VEE. These benefits include more accurate readings, the near elimination of estimates for billing and the reduced need for access to customer premises.

VEE is a requirement of the MDMR when time-of-use rates are calculated “off meter” since any missing meter readings must be estimated before the data can be compiled into the correct rate “bucket”. The customer benefit from a VEE-enabled MDMR is derived from the improved quality of the meter reading data and the ability to accommodate more complex time-based rates. Without VEE, gaps will exist in the MDMR data. These data gaps have to be filled when modeling complex rates and estimating system losses, as well as for calculating time-based electricity consumption. Performing these estimates within the MDMR ensures the consistency and usability of consumption data for a variety of purposes.

Q40.4 Does FortisBC expect that, as the number of meter readings reported to customers goes up dramatically because of the “time buckets,” that customer satisfaction might actually fall? Please discuss.

A40.4 Although hourly readings will be available to customers if desired (through the web or with an in-home display device, for example), customer bills will continue to be based on actual monthly or bi-monthly readings until time-based rates are developed and approved. The AMI system will ensure bills are based on actual readings, which will have a positive impact on customer satisfaction by reducing bills based on estimated consumption.

41.0 Reference: VEE

Exhibit B-6, p. 8

FortisBC states: "AMI systems utilizing VEE capabilities are prevalent in many jurisdictions including California, Texas and Ontario."

Q41.1 Please provide a more detailed breakdown of the prevalence of VEE capabilities across similar sized AMI initiatives in North America.

A41.1 FortisBC is unable to find information at this level of detail, other than for BC Hydro which FortisBC understand also intends to implement a VEE-enabled MDMR. Most AMI specification and RFP documents are confidential and therefore not publicly available.

Q41.2 Where and why is VEE not being included in North America? Please explain.

A41.2 VEE is generally employed in utilities delivering hourly interval readings through the AMI system. Therefore, VEE is not likely to be included by utilities that have not implemented AMI, or have implemented AMI with only daily or monthly readings. As stated in the response to BCUC IR No. 3 Q41.1 above, FortisBC was unable to find detailed information in this regard.

Q41.3 Please confirm the incremental capital cost associated with the additional VEE capabilities is $4 million.

A41.3 The incremental cost of a VEE equipped MDMR including testing and implementation costs is $3.5 million (excluding AFUDC and including contingency) as shown in Amended table 6.3 under "IT Infrastructure and Upgrades" on page 13 of the Amended Application (Exhibit B-6).

Q41.4 Please indicate what portion of the additional operating expenses ($727

thousand per year vs. $524 thousand per year) summarized in Amended Table 4.1.1 is associated with providing VEE capabilities.

A41.4 As described in Section 5 of the Amended Application (Exhibit B-6), the increased software maintenance costs associated with the VEE equipped MDMR is approximately $0.2 million per year.

Q41.5 Given FortisBC has not yet developed specific programs to utilize the VEE functions, please provide an illustrative break-even analysis illustrating the amount of load in FortisBC's system that would have to be shifted from HLH to LLH over a ten-year period under different assumptions for the cost differential between HLH and LLH energy in order to offset the incremental capital and operating costs associated with the VEE capabilities in the amended Application.

A41.5 As discussed in the response to BCUC IR No. 3 Q38.8, the avoided cost of generation, transmission and distribution capacity is between $200,600 and $280,600 per MW. Therefore, between 9.3 MW and 13.0 MW (approximately 1.4 percent to 2.0 percent) of peak load would have to be shifted from HLH to LLH periods to offset the estimated $2.6 million 10-year net present value of incremental capital and operating costs of the VEE-enabled MDMR.

42.0 Reference: Hourly Readings

Exhibit B-6, 3. Hourly Reading, p. 6

FortisBC states, "Combined with the HAN, this more detailed information will help FortisBC customers understand their energy consumption patterns, respond to time-based rates and reduce their energy usage. This will provide customers with useful information about their electricity consumption to allow them to make informed choices."

Q42.1 In addition to the AMI meters themselves, please discuss what other devices (in-home displays, appliance controllers, etc.) will be required in order for customers to respond effectively to time-based rates. Please estimate any costs not included in the present Application and indicate whether they would be paid by FortisBC or by the homeowner.

A42.1 As described in response to BCUC IR No. 3 Q38.4.1 and Q38.4.3, FortisBC will not have the ability to estimate the effect of in-home displays and load control devices prior to the implementation of AMI, but intends to use customer use data subsequently in it review of possible time-based rate structures.

The cost of implementing appliance controllers (load controls) is estimated to be $75 per load control device, and in-home display units range from $75 to $300 depending on the complexity of the unit and its degree of integration with heating and appliances.

At this point, FortisBC has not determined whether the devices would be provided by the utility or would be the responsibility of customers. This decision is linked to the design of any time-based rates. If the time-based rate was mandatory or complex (the number of time buckets and/or seasonal or other changes in their definition) or if the on-peak rate was significantly higher than the off-peak rate, then it may be necessary for the utility to provide customers with in-home display units to help them manage consumption. If the rate is voluntary or relatively simple to manage, it may be more appropriate to leave the choice to purchase an in-home display device to the customer.

For this reason, the costs of the in-home display units and load control devices are not included in the AMI Project costs but may be the subject of a future application.

Q42.2 Given the marginal cost of both energy and capacity provided in response to previous questions, please estimate the potential cost savings achievable by a customer through the AMI and associated technology. (The Commission appreciates that FortisBC has not completed detailed rate-design work, but would appreciate some best estimates in this regard.) From this information, please estimate the payback period for a typical residential customer's investment in AMI and related technologies.

A42.2 Please see the response to BCUC IR No. 3 Q59.4. The 0.11 percent rate impact of the AMI project on a residential customer is expected be smaller than the expected 0.6 percent – 10.0 percent savings achievable through AMI and the associated future technology.

Q42.3 Is FortisBC aware of any research on how far in advance a customer must be made aware of price changes, such as those that might be associated with critical peak pricing, to make meaningful changes in consumption? Please provide any references.

A42.3 FortisBC is not aware of any research on customer notification of CPP price changes. Research into this and other aspects of CPP rates will be necessary if FortisBC is to propose this type of rate design in the future.

43.0 Reference: Exhibit B-6, 3. Hourly Reading, p. 6

Q43.1 Please describe any significant differences between "on meter" and "off meter" designs with respect to required communication infrastructure, capital cost, and operating cost.

A43.1 In addition to the comparison provided in Table 1 of the Amended Application, please see Table A43.1 below for a comparison.

Table A43.1: Comparison "On Meter" and "Off Meter"

	On-Meter	**Off-Meter**
Communications Infrastructure	Bandwidth to support daily readings	Bandwidth to support hourly readings
Capital Costs	$31.3 million	$37.3 million
Operating Costs	Dependent on complexity of changes to buckets and times as well as what meter upgrades can be done "over the air".	$200,000 per year for software maintenance

44.0 Reference: Hourly Readings
Exhibit B-6, p. 9
Bandwidth Requirements

FortisBC states: "Hourly readings require a greater bandwidth than the daily readings required by On Meter."

Q44.1 Is the greater bandwidth and associated costs included in the Amended Application?

A44.1 Yes.

45.0 Reference: Hourly Readings
Exhibit B-6, p. 25, Amended BCUC 1.6.6
Line Losses

Q45.1 Please provide additional commentary on how hourly readings will make it easier to match feeder to meter consumption and to analyze distribution line losses.

A45.1 When hourly data is available at customer endpoints, it can be compared to hourly readings taken at the substation feeders. Following is a summary of the process:

- Select a desired hourly interval.
- Retrieve the substation feeder hourly energy readings for this interval from the Substation Automation Data Historian database.
- Retrieve and totalize all customer meters connected to the relevant feeder for the same interval.
- Subtract these two values to give the “unmetered power” for the interval.
- Finally, subtract any known fixed, unmetered loads (i.e. streetlights, cable amplifiers, etc.) to determine the system losses.

Since the known fixed loads discussed above may be significant and vary depending on the time of day (i.e. street lighting), hourly interval data is considered more useful to determine the true feeder losses.

Q45.2 Please discuss the opportunities for reducing line losses as a result of this information.

A45.2 Once the loss calculation described in the response to BCUC IR No. 3 Q45.1 is completed, then potential causes can be investigated. Unusually high line losses could be caused by unknown un-metered loads or power diversions requiring further investigation. If the losses are solely due to resistance losses in conductors or transformers, then capacity upgrades (i.e. larger conductors) could be considered to improve the transmission efficiency of the system.

Q45.3 If possible, please provide an estimate of the reduction in line losses?

A45.3 Given the uncertainty of the causes of the line losses, it is not possible at this time to provide an estimated reduction. However, as discussed in the Distribution Substation Automation Project CPCN, a 1% (absolute) savings in energy by reducing system losses results in a potential savings of $2.4 million (Reference: FortisBC Distribution Substation Automation Project CPCN, BCUC IR2, A34.2, pp 10-18.)

46.0 Reference: Functional Requirements
Exhibit B-6, 3. 4. Revisions to Functional Requirements, pp. 10-11
Specifications

Q46.1 Provide a copy of the FortisBC specification document in confidence.

A46.1 The detailed specification and requirements document required for the RFP process will be completed after approval of the CPCN application. There are two reasons for this. First, FortisBC intends to use an AMI specialist to assist in the design of the functional requirements. The Company feels that this is an expense that should not be incurred until the CPCN application is approved. Second, the high level requirements detailed in Amended Table 7.1 (Exhibit B-6) need to be confirmed through approval of the Amended Application before detailed requirements can be established.

Q46.2 Does the FortisBC AMI specification exceed the required minimum level of functionality for AMI in the Province of Ontario as spelled out in AMI Functional Specification – Version 2 (July 2007) for residential and small general service consumers where the metering of demand is not required?

A46.2 FortisBC's AMI specification meets but does not exceed the minimum level of functionality as identified in the Ontario Functional Specification (July 2007) Section 2.2 – Minimum Functionality which reads as follows:

> AMI shall collect Meter Reads on an hourly basis from all AMCDs deployed by a distributor and transmit these same Meter Reads to the AMCC and MDM/R, as required, in accordance with these Specifications; and
>
> A Meter Read shall be collected, dated and time stamped at the end of each hour (i.e. midnight as represented by 24:00).
>
> The date and time stamping of Meter Reads shall be recorded as year, month, day, hour, minute (i.e. YYYY-MM-DD hh:mm).
>
> All meters shall have a meter multiplier of one (1).
>
> Distributors shall provide the MDM/R with the service multiplier for transformer-type meters. (this item would not be applicable to FortisBC).

Q46.3 Does FortisBC have a net metering program available to its customers?

A46.3 FortisBC does not have a net metering tariff at this time. It is the Company's intention to file a net metering tariff application in 2008. However, FortisBC does permit customer generation to be interconnected with its network as outlined in the FortisBC Electric Tariff Section 10.1.

> *10.1 Parallel Generation Facilities*
>
> *The Customer may, at its expense, install, connect and operate its own electrical generating facilities to its electrical circuit in parallel with the Company's electrical system provided that the manner of installation and operation of the facilities is satisfactory to the Company, and the facilities have the capacity to be immediately isolated from the Company's system in the event of disruption of service from the Company.*

In addition, it is FortisBC policy to purchase the generation of such interconnected customers if requested.

Q46.3.1 Can the FortisBC AMI specification support customer Net Metering?

A46.3.1 Yes, the AMI enabled meters will support customer net metering.

Q46.3.2 What is the estimated cost of adding net metering?

A46.3.2 As net metering capabilities are standard on most AMI enabled meters that support the other requirements listed in Amended Table 7.1 (Exhibit B-6), there is expected to be no incremental cost to provide this functionality.

Q46.4 What is the estimated cost of adding instantaneous demand kW?

A46.4 FortisBC understands this question to refer to instantaneous peak demand. Instantaneous demand as kW is either a standard feature, or is not included by the vendors, and therefore providing a cost for the addition of this feature is not possible. Features like instantaneous demand, less than hourly readings, tamper detection, and voltage readings are typically either included as a standard features in a total cost package, or are not included by the vendor, therefore, it is not possible to isolate the costs associated with the addition of these features. Furthermore, FortisBC does not know at this time whether a “package” including this feature, in addition to the required features, is available from potential vendors.

Although instantaneous demand is not a requirement, preference will be given to vendors that can provide this functionality provided that the meter and infrastructure being quoted to accommodate the other functional requirements can already provide this reading without additional investment.

Q46.5 What is the estimated cost of adding less than hourly readings?

A46.5 Adding less than hourly readings for select customers being profiled by FortisBC is not expected to add incremental costs into the AMI project. In the case that less than hourly readings were required for all customers, please refer to BCUC IR No. 3 Q46.4.

Q46.6 What is the estimated cost of adding voltage readings?

A46.6 Most AMI systems that support the features already identified in the Amended Table 7.1 also support voltage readings. Please refer to the response to BCUC IR No. 3 Q46.4.

Q46.7 What is the estimated cost of adding tamper detection?

A46.7 Most AMI systems that support the features already identified in the Amended Table 7.1 also support some sort of tamper detection capabilities. Please refer to BCUC IR No. 3 Q46.4.

Q46.8 Is the proposed AMI system:

Q46.8.1 Capable of collecting energy usage data at a level that supports customer understanding of hourly usage patterns and their relation to energy costs?

A46.8.1 Yes, the proposed AMI system is capable of collecting energy usage data at a level that supports customer understanding of hourly usage patterns and their relation to energy costs.

Q46.8.2 Capable of allowing access to personal energy usage data such that customer access frequency does not result in additional AMI system hardware costs?

A46.8.2 Yes, the proposed AMI system is capable of allowing access to personal energy usage data without any additional AMI system hardware costs, regardless of customer access frequency.

Q46.8.3 Compatible with applications that provide customer education and energy management information (HAN)?

A46.8.3 Yes, the proposed AMI system is compatible with applications that provide customer education and energy management information.

Q46.8.4 Capable of ensuring the security of meter data transmission from the customer meters to the AMI host system so that only authorized devices provide and receive meter data?

A46.8.4 Yes, the proposed AMI system is capable of ensuring the security of meter data transmission. The exact requirements relating to the security functionality of the AMI system will be specified during the RFP process.

Q46.8.5 Capable of data interfaces between other utility data systems as well as interfaces with DR networks and systems?

A46.8.5 Yes, the proposed AMI system will be capable of utilizing data interfaces between other utility system including DR networks and systems.

Q46.9 The following list[3] is a compilation of typical specifications listed by a number of utilities in their recent AMI request for proposals.

A46.9 The creation of a detailed RFP specification document is expected to be the next step once FortisBC has received approval of the CPCN Application. Therefore, the following questions are answered in the context of FortisBC's

[3] 2007 Assessment of Demand Response and Advanced Metering Staff Report Federal Energy Regulatory Commission September 2007

expectations.

Q46.9.1 Would FortisBC please indicate if the following functionality has been included in their RFP specification?

Q46.9.1.1 The ability to provide time-stamped interval data for each customer, at least hourly, but often as short an interval as 15 or 30 minutes,

A46.9.1.1 FortisBC will be requiring time-stamped interval data for each customer hourly. 15 or 30 minute increments will only be required for select customer profiling rather than for all customers.

Q46.9.1.2 The option of remote disconnect/connect for some or all meters,

A46.9.1.2 Yes, the vendors will be required to support remote disconnect / reconnect as an option and quote a price per meter for the option as part of the RFP.

Q46.9.1.3 The ability to remotely upgrade meter firmware,

A46.9.1.3 Yes, this will be a requirement subject to Measurement Canada regulations regarding the types of upgrades allowed under the meter glass.

Q46.9.1.4 The ability to send messages to equipment in or around customer home to support demand response,

A46.9.1.4 Yes, the RFP will require a communications infrastructure capable of supporting interfaces with load control devices and in home displays.

Q46.9.1.5 The positive notification of outage and restoration (promising both significant cost savings and customer service benefits),

A46.9.1.5 Yes, the RFP will require outage and restoration notification to assist FortisBC in identifying and resolving outages more effectively.

Q46.9.1.6 The capability to remotely read meters on-demand,

A46.9.1.6 Yes, the AMI system will be required to support on-demand readings initiated by an AMI system operator.

Q46.9.1.7 The voltage flagging capability if voltage is outside of range configurable by utility,

A46.9.1.7 Voltage readings are not considered a requirement of the AMI system. However, preference will be given to vendors that can provide this functionality without additional cost.

Q46.9.1.8 The voltage interval reading capability at same interval as meter readings,

A46.9.1.8 Voltage readings are not considered a requirement of the AMI system. However, preference will be given to vendors that can provide this functionality without additional cost.

Q46.9.1.9 The tamper flagging capability,

A46.9.1.9 Tamper flagging is not considered a requirement of the AMI system. However, preference will be given to vendors that can provide this functionality without additional cost. FortisBC's response to BCUC IR No. 3 Q56.2 further discusses tamper detection capabilities.

Q46.9.1.10 The memory to store specified number of days of readings on meters (anywhere from seven to 45 days, depending on the utility),

A46.9.1.10 FortisBC will require that the meter be able to store at least thirty days of readings (assuming hourly reads).

Q46.9.1.11 Support for some form of prepay metering,

A46.9.1.11 More frequent reading data would allow customers to prepay and FortisBC to identify customers that have nearly reached their prepaid amount and to provide notification to these customers to make additional prepayments. In addition, the option of adding remote disconnect/reconnect to these customers would allow FortisBC to support the prepay process without physically attending to the customer premise which could otherwise prove costly and inconvenient to the customer.

Q46.9.1.12 The daily register reading of meters, often at midnight,

A46.9.1.12 Yes, FortisBC will require the daily register reading of meters to be transmitted at least one per day, although the specific time it will be required has not been determined.

Q46.9.1.13 The inclusion of data warehousing systems -- seen as increasingly necessary to store large volumes of data gleaned from AMI and meter data management systems (MDM),

A46.9.1.13 Yes, FortisBC will require the vendor to provide solutions on the best way to store and access data that has been gathered by the AMI system.

Q46.9.1.14 The tight integration with MDM into overall operations management systems with links to accounting, billing, reporting, outage management, and other operations systems, and

A46.9.1.14 Yes, FortisBC will be requiring interfaces with both of the billing and field mapping systems as part of the AMI RFP.

Q46.9.1.15 The ability to extend AMI and smart grids to multiple in-home appliances connected together as part of a home-area network (HAN).

A46.9.1.15 Yes, FortisBC will require the communications infrastructure to be in place to support load control devices and in-home displays.

47.0 Reference: Project Costs
Exhibit B-6, BCUC IR No. 1 Amended Application, pp. 26-29
Existing Meters

Q47.1 As these existing meters are no longer used and useful, would FortisBC please explain why these costs of $8.9 million should be recovered from the ratepayers and not the shareholders? Please explain.

A47.1 The Company is of the opinion that the AMI Project is supportive of both the BC Energy Plan and Bill 15 and will ultimately benefit customers by lowering operating costs and provide demand response capabilities. Therefore FortisBC is of the opinion that the cost of the existing meters should be recovered from customers.

48.0 Reference: Project Costs

Exhibit B-6, BCUC IR No. 1 Amended Application, p. 40

Outsourcing Metering and IT Installation

Q48.1 Has FortisBC considered outsourcing the AMI Program including the IT portion? Please explain.

A48.1 In reference to outsourcing the entire AMI project, FortisBC feels that this approach would be cost prohibitive and furthermore would not prepare the Company to use and manage the AMI system after implementation. However, FortisBC's RFP will ask vendors to quote the cost of the both the installation of meters and the implementation of the required IT systems and interfaces. At this stage, it is expected that the vendor will be managing these installations although FortisBC will remain actively involved and will be responsible for managing the overall execution of the project. This approach will leverage the experience of the AMI vendors and specialists while ensuring that FortisBC understands and can manage the technology after implementation.

49.0 Reference: Economic Life

Exhibit B-6, BCOAPO IR 1 Amended Application, p. 55 and Exhibit B-6, BCOAPO IR 2 Amended Application, p. 94

Amortization Period

The Ontario Energy Board, 2007 EDR Smart Meter Rate Calculation Model has the defaults set so that Smart Meter Amortization Rate is 15 years, Computer Hardware Amortization Rate is five years and Computer Software Amortization Rate is three years.

The Essential Service Commission in their Guidance Paper section 3.3 Regulatory depreciation[4] states "Regulatory depreciation is a component

[4] Essential Services Commission, Advanced Metering Infrastructure Review: Final Framework and Approach Volume 1 Guidance Paper, December 2007

of the revenue requirement for prescribed metering services and represents the annual rate at which accumulated capital is returned to investors. It is a function of the regulated asset base and the period over which the assets are depreciated. The Order stipulates the asset lives for metering assets and IT and telecommunications assets that must be used in determining the distributors' revenue requirements. Clause 4.2(f) of the Order states that in determining the maximum charges, the Commission must:

> **…use asset lives of 15 years in respect of metering assets; 7 years in respect of telecommunications systems and IT systems".**

Also FERC [5]states "Another cost-recovery barrier raised at the FERC Technical Conference is the disconnect between the economic life of advanced metering infrastructure and its accounting depreciation period. Southern California Edison (SCE) reports that 'many utilities, including us, are concerned about the potential that AMI technology will not last as long as its depreciation period… Since the ANSI meters and communication networks will have to operate in very difficult environmental conditions over a long time, if the life of these systems falls short, this could result in significant cost impacts for our customers.' Aligning the economic life with the accounting life will remove this disincentive".

Idaho Power[6] states in their AMI Implementation Plan of August 31, 2007 that "The AMI meters have a 15-year life".

[5] FERC, 2006 Assessment of Demand Response and Advanced Metering, p. 129
[6] Supplement to Phase I AMI Implementation Status Report Case No. IPC- 06-01, filed in compliance with Idaho Public Utilities Commission Order No. 30102

Q49.1 In light of the above and other references:

Q49.1.1 Does FortisBC consider the Smart Meter to have an economic life of 15 years without encountering technical obsolescence?

A49.1.1 It is difficult to estimate when the technology described in the Amended Application will be sufficiently technically obsolete to warrant replacement. Any decision as to whether the AMI system should be replaced after 15 years due to technical obsolescence will have to be made on a business case basis at that time, and one factor that should be considered in the analysis is the sunk costs of the existing system.

Q49.1.2 Does FortisBC consider the Computer Software to have an economic life of three years without encountering technical obsolescence?

A49.1.2 No. FortisBC considers the Computer Software to have an economic life of at least 10 years without encountering technical obsolescence for several reasons:

(i) The software is a database that holds AMI reading data and performs estimates. Because much of the functionality is adaptable and rule-based, the system does not need to be fully replaced and generally can be easily enhanced to match any future business requirements.

(ii) The AMI operating expenses contain software maintenance fees over the life of the project to account for upgrades to the software which will prolong the life and keep the software up to date.

(iii) Historically, FortisBC has not replaced major IT systems as frequently as every three years. The CIS Billing system as an example has been in place for eight years.

Q49.1.3 Does FortisBC still consider the Communication Network Systems to have an economic life of five years without encountering technical obsolescence?

A49.1.3 It is difficult to estimate when the communication network described in the Amended Application will be sufficiently technically obsolete to warrant replacement. Any decision as to whether the communication network should be replaced after 5 years due to technical obsolescence will have to be made on a business case basis at that time, and one factor that should be considered in the analysis is the sunk costs of the existing network.

50.0 Reference: Other Jurisdictions
Exhibit B-6, Amended Application, p. 8
AMI Market Penetration

FERC states "The results of the FERC Survey indicates that advanced metering or AMI currently has a low market penetration of less than six percent in the United States (See Figure III-4). This result is lower than past estimates, which had suggested the penetration rate was closer to 10 percent."

Federal Energy Regulatory Commission, Assessment of Demand Response and Advanced Metering, Staff Report August 2006, Chapter III – Advanced Metering Penetration, pages 26-27, shows that US market penetration is at about 6% and will rise to over 20%[7] by the end of 2010.

[7] FERC, 2007 Assessment of Demand Response and Advanced Metering, p.31, footnote 164

Q50.1 With similar AMI functionality:

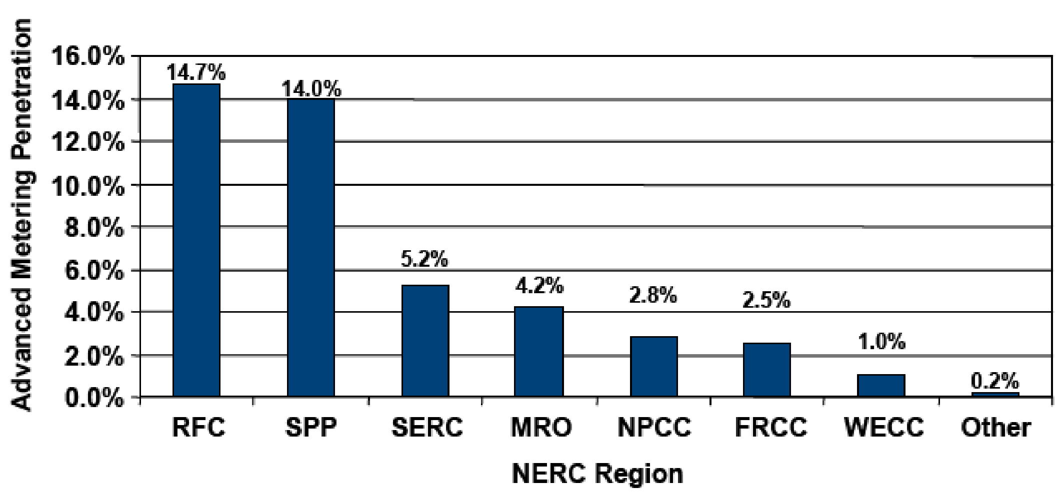
Q50.1.1 What is the current AMI market penetration in percent in the United States of America by state?

A50.1.1 FortisBC is not able to find any studies completed after the August 2006 FERC study noted above. FERC is completing an update to that study later this year which will likely provide an update to these figures. In 2006, the market penetration was, by region, as follows:

[5] Regional definitions used in this figure and subsequent figures are (See Chapter I for a NERC region map):

- Electric Reliability Council of Texas, Inc. (ERCOT)
- Florida Reliability Coordinating Council (FRCC)
- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability*First* Corporation (RFC)
- SERC Reliability Corporation (SERC), which covers most of the Southeast.
- Southwest Power Pool, Inc. (SPP)
- Western Electricity Coordinating Council (WECC)
- Other (Alaska and Hawaii)

Figure ES-1. Penetration of advanced metering by region[5]



The following table illustrates the states with the highest penetration of AMI:

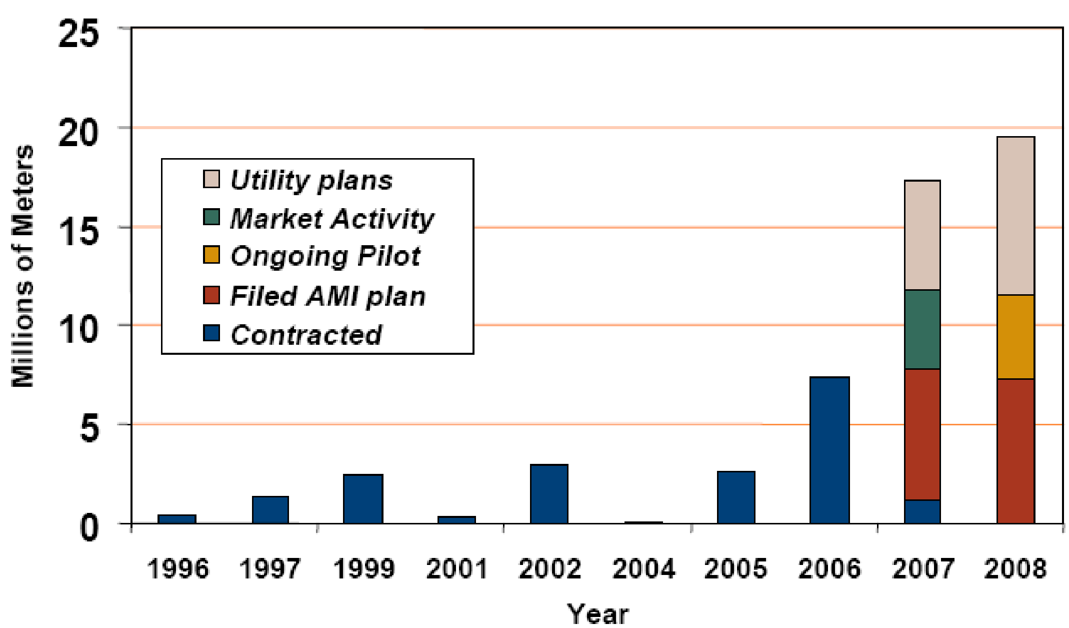
Table ES-1. States with the highest penetration of advanced metering

State	Advanced Metering Penetration
Pennsylvania	52.5%
Wisconsin	40.2%
Connecticut	21.4%
Kansas	20.0%
Idaho	16.2%
Maine	14.3%
Missouri	13.4%
Arkansas	12.9%
Oklahoma	7.2%
Nebraska	6.8%

Source: FERC Survey

The following chart depicts the actual and projected AMI market deployments up until 2008.

Figure III-2. AMI market activity, actual and projected



Source: 2006 FERC AMI and DR study

Q50.1.2 What is the current AMI market penetration in percent in Canada by province?

A50.1.2 FortisBC does not have market penetration information for the Canadian marketplace but is aware of the following planned implementations (numbers are approximate):

FortisAlberta:	405,000 meters
Enmax:	400,000 meters
BC Hydro:	1.4 million meters
Ontario SMI:	4.5 million meters
Sask Power:	450,000 customers
Manitoba Hydro:	500,000 customers

Q50.1.3 Would FortisBC please provide a listing of American states that are in favour of AMI, that more study is needed, or that decided to not proceed with AMI?

A50.1.3 FortisBC was not able to find the information requested above. However, the following state update on AMI implementations was obtained from the FERC September 2007 AMI update.

State	Activity
California	PG&E—received approval of its Smart Meter project application from the CPUC. SDG&E—received approval of its smart meter project following a settlement with the utility, the PUC's Division of Ratepayer Advocates, and advocacy group the Utility Consumers Action Network.[136] SCE—requested approval for its Phase II AMI Pre-Deployment Activities and Cost Recovery Mechanism is pending before the CPUC.[137]
Connecticut	The state of Connecticut passed a new DR-AMI bill requiring utilities in the state to: ○ install new "smart" meters and associated technologies capable of measuring real-time prices, in support mandatory TOU pricing. ○ deploy AMI by January 1, 2009.[138] Connecticut Light & Power—submitted its AMI plan, which is pending before the DPUC.[139]
District of Columbia	The DC PSC approved a pilot program (PowerCentsDC), which allows residential customers involved with the pilot to test three different pricing schedules.[140] It is said to be a first of its kind pilot in the electric industry.[141]
Maryland	BG&E—the MD PSC approved BGE's demand-response pilot program[142] and BGE's request for rate schedule changes and surcharges to cover a Phase I pilot of the proposed AMI deployment.[143] Pepco—filed for authority to establish surcharges to support DSM and AMI deployment initiatives;[144] and received approval to establish a DSM Collaborative and AMI Advisory Group.[145] The DSM Collaborative would review and discuss Pepco's proposed DSM programs. The AMI Advisory Group would "be kept apprised of the progress, status, components and development of Pepco's AMI installation."[146] Pepco proposed that the advisory group be comprised at minimum of Pepco, the Maryland PSC, the Office of People's Counsel (OPC), and the Maryland Energy Administration.[147]
New York	New York State Public Service Commission (NYSPSC)—issued an Order requiring electric utilities to conduct AMI cost-benefit studies and file comprehensive plans for development and deployment of advanced metering systems.[148] Con Edison and Energy East (Rochester Gas & Electric (RG&E) and New York State Electric & Gas (NYSEG))—have filed their plans.[149] In its plan, Energy East suggested that with NYSPSC approval, RG&E and NYSEG could begin meter installation as early as 2008.[150] Con Edison–filed a proposal for an electric rate increase which included $340 million to install AMI and AMR (May 4, 2007).[151]

Ohio	PUC of Ohio—adopted recommendations to require state electric distribution companies to file reports that included a list of advanced metering technologies and costs.[152] In that same decision, the PUC of Ohio "indicated that all electric distribution utilities should offer tariffs to all customer classes, which are, at a minimum, differentiated according to on- and off-peak wholesale periods. Moreover, it noted that time-of-use meters should be made available to customers subscribing to the on- and off-peak tariffs."[153] PUC of Ohio—initiated proceeding 07-646-EL-UNC to establish AMI workshops to study the cost/benefits of AMI deployment strategies and cost recovery mechanisms.[154] The first workshop was set for July 26, 2007.[155]
Pennsylvania	PA PUC—tasked the Pennsylvania Demand Side Response Working Group to perform cost-benefit assessments for all utilities to further develop their advanced metering infrastructure.[156] Commonwealth of Pennsylvania— issued a policy statement stating the public should have access to historic billing data and real time metered data to facilitate retail choice, demand side response, and energy conservation initiatives.[157]
Texas	State of Texas—passed legislation (House Bill 2129) in 2006 allowing utilities to use surcharges to fund advanced meters.[158] PUC of Texas—issued a proposed rulemaking that lists minimum functionality criteria utilities would be required to meet with their advanced metering deployments. The Texas rulemaking added several advanced capabilities to the minimum functionality criteria, such as two-way communications, capability to provide timely customer usage data to retail electric providers, capability for customers to receive pricing signals from their retail electricity providers or a designated customer agent, and the ability to upgrade capabilities as technology advances.[159] The proposed rulemaking also states that an electric utility "shall not deploy an AMS (advanced metering system) that has not been successfully installed previously with at least 500 advanced elsewhere in the world, except for pilot programs."[160] On September 29, 2006, the PUC of Texas reported to the Texas legislature its finding that there are no barriers to AMI in Texas.[161]
Vermont	Vermont Public Service Board—opened a docket requiring both statewide AMI and utility-by-utility AMI cost-benefit studies.[162]

Source: Table III-1 FERC Assessment of Demand Response and Advanced Metering 2007

51.0 Reference: BC Hydro Smart Metering Initiative ("SMI")
Exhibit B-6, Amended Application, pp. 8, 16
SMI and AMI

Q51.1 Please provide a comparison of the functionality of AMI and BC Hydro planned SMI and highlight any differences and enhancements between the two systems.

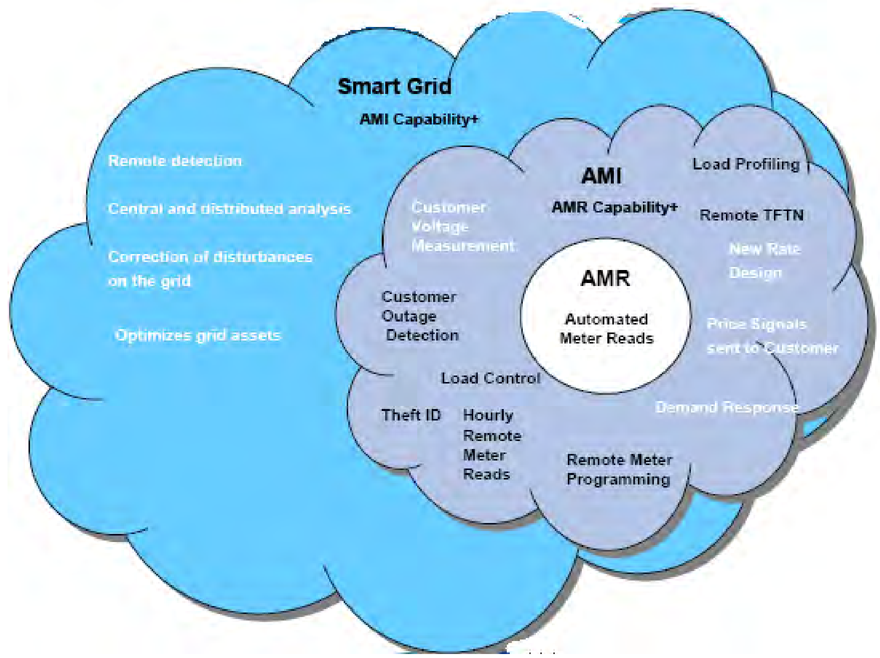
A51.1 Although FortisBC does not have access to the detailed functional requirements of the BC Hydro SMI system, based on information from BC Hydro's web site and as confirmed through FortisBC's discussions with BC Hydro, the SMI project will consist of the following functionality:

- Hourly readings;
- Validation, Estimation and Editing capable MDMR;
- Home Are Network capable;
- Outage and restoration verification from each meter; and
- Remote disconnect capable.

However, FortisBC understands that BC Hydro's project scope has not been finalized and therefore is still subject to change. This is consistent with the functionality proposed in FortisBC's current application.

Q51.2 Would FortisBC please clarify any additional future costs may be incurred to upgrade to Smart Grid?

A51.2 FortisBC assumes the question refers to the Smart Grid functionality shown in the diagram previously submitted in response to BCUC IR No. 2 Q21.2.



As described in the BCUC Amended Application IR No. 2 Q21.2, the Amended Application supports most of the AMI and all of the AMR functionality in the diagram.

The additional “Smart Grid” functionality shown in the diagram is not part of the Smart Grid and would likely require additional expenditures to implement:

- Remote detection;
- Central and distributed analysis;
- Correction of disturbances on the grid; and
- Optimizes grid assets.

Q51.2.1 If there are any additional upgrade costs to Smart Grid, would FortisBC please provide a magnitude estimate of these costs?

A51.2.1 The concept of a “Smart Grid” is still evolving, and the additional functionality described in response to BCUC IR No. 3 Q51.2 is insufficient to define the scope of a Smart Grid implementation in the FortisBC service territory. FortisBC intends to implement Smart Grid functionality in a phased approach where it makes economic sense, pending regulatory approval. The wide range of scope and scale of potential Smart Grid implementations means that future costs could vary between $1 million and $50 million. Actual expenditures will depend to a large extent on any benefits that can be achieved.

Q51.3 Is FortisBC aware of the regulations referred to in Utilities Commission Amendment Act, 2008 ("Bill 15")?

A51.3 FortisBC is aware of the Utilities Commission Amendment Act, 2008 but does not know what the final form of the regulations will include.

Q51.3.1 Will FortisBC be in compliance with these regulations and is FortisBC prepared to comply with any additional regulations that are not already covered in their amended Application?

A51.3.1 Given the wording in section 64.04 of the UCA, FortisBC does not believe that the regulations relating to smart metering will apply to FortisBC. If new regulations are made pursuant to the Utilities Commission Act as amended by Bill 15 which apply to FortisBC then FortisBC would endeavour to comply with its legal obligations.

Q51.4 In Bill 15, BC Hydro must complete the installation of smart meters by 2012.

Q51.4.1 To be reasonable and prudent, would FortisBC consider combining and coordinating the supply of the AMI project with the BC Hydro SMI project for an in-service date of 2012? Would FortisBC please explain the advantages and disadvantages of this approach?

A51.4.1 Please see the responses to BCUC IR No. 2 Q21.7 and Q21.8 (Exhibit B-3). FortisBC's reasoning has not changed following the enactment of Bill 15.

Q51.5 On March 31, 2008 the National Association of Regulatory Utility Commissioners[8] (NARUC) named 16 State Commissioners to serve on the joint federal-state Smart Grid Collaborative.

Q51.5.1 As one of the goals of this group is "to determine the functional requirements of the technologies that the utilities will install and to ensure that systems are built to a consistent set of technical standards to provide maximum benefit, quality, and interoperability to electricity consumers", would FortisBC please explain how they will provide this Smart Grid concept while remaining compatible with the BC Hydro SMI program?

A51.5.1 It is unclear exactly what "Smart Grid technical standards" may directly impact electricity consumers. The highest-level functionality specifically associated with the Smart Grid in the diagram supplied in BCUC IR No. 2 Q21.2 (Exhibit B-3) does not directly impact electricity consumers, nor is inter-utility compatibility critical since the Smart Grid largely relates to the distribution system.

FortisBC assumes that the NARUC Collaborative will consider elements of AMI systems that directly impact residential customers. In particular, the Home Area Network and the associated devices, including in-home displays, programmable thermostats, load control devices and smart appliances will have direct impact on consumers.

[8] National Association of Regulatory Utility Commissioners, Sixteen State Regulators Join NARUC-FERC Smart Grid Collaborative, March 31, 2008 Release.

Interoperability and quality of devices that connect to the HAN would be of some concern to FortisBC customers.

BC Hydro and FortisBC agree that the most probable requirement of compatibility between the two utilities relate to devices that connect to the HAN. Ideally, consumers will be able to use devices purchased for use in BC Hydro service territory and use them without modification in FortisBC territory. FortisBC will continue to work with BC Hydro to ensure an appropriate level of compatibility in this area.

52.0 Reference: Deferral Analysis
Exhibit B-6, pp. 71-78, Amended BCUC 1.13.1

Q52.1 In calculating the benefit (cost) of deferring the AMI project, FortisBC shows different costs for both the AMI and status quo alternatives. Please explain why FortisBC has computed different costs for the status quo. Should the status quo not be the same in each case? All that changes with the deferral of the AMI project is that the status quo continues for some longer portion of the AMI scenario until the AMI is implemented. Please refile the deferral analysis in which the status quo is held constant and all that changes is the timing of the AMI project. Please include the additional costs of maintaining the existing system for the years the AMI project is deferred as part of the AMI project cashflows. If the Company does not agree with this methodology please provide a justification for its current methodology.

A52.1 The Company does not agree with this methodology since the cost of the Status Quo changes depending on its durations, that is, on how long the AMI project is deferred. If the scenario(s) requested did not include deferral of the AMI project, then the comparative NPV for the Status Quo would not change. When comparing various deferral options, the results for the Status Quo change under each deferral alternative due to the fact that the Company continues to incur the cost of reading meters using the existing methods and processes while the benefit of the reduced cost associated with AMI is deferred. Therefore, the appropriate comparison is to illustrate the impact of deferring the project under both the Status Quo and AMI options.

53.0 Reference: Project Costs
Exhibit B-6, BCUC IR A16.6, p. 42 and
Exhibit B-6, p. 2
Estimate Accuracy

FortisBC states that "The cost estimates for the additional features in the Amended Application were developed in a manner consistent with the internal costs within the Original Application. These costs would fall under Class Four within the AACE recommendations for classifying cost estimates (+/- 15 to 60 percent)."

As this amendment is estimated to increase the AMI Project cost by $6.0 million to $37.3 million, would FortisBC please provide the accuracy and AACE class of the Amended Application?

A53.0 The accuracy and AACE classes for the AMI project are summarized (without AFUDC) as follows:

Amended Application	$5.8 million	Class Four
Internal FortisBC Costs	$2.8 million	Class Four
Vendor Costs	$28.0 million	Class Three

54.0 Reference: Project Costs
Exhibit B-6, 6. Revision to Project Costs, and
7. Revision to Rate Impact Analysis, pp. 12-15
Total Cost/Benefit Analysis

Q54.1 Assuming the Total Cost of AMI is the cost to the Utility and the cost of AMI supported equipment to its customer then would FortisBC please add the cost to the customer for in-house Han devices as a negative benefit in the following requested analysis?

A54.1 FortisBC's analysis reflects all 108,000 customers purchasing and in-home display at a cost of $75 each following the completion of the AMI installation.

Q54.2 Please provide working electronic (not password protected) spreadsheets as well as hardcopy of a Total Summary of Project Cost (Exhibit B-2, Table 6.3), Exhibit B-1, Table A16.12 and Table A17.1.

Table A16.12: Amended Capital Cost Summary (add rows as required)

	Direct Cost	Indirect Cost	Total
	($000s)		
Meters and Modules			
SMI Vendor Training			
Network Infrastructure			
IT Infrastructure and Upgrades			
MDMR - Meter Data Management Repository			
VEE			
HAN			
Project Management			
Network Design and Testing			
AFUDC			
IDC			
Subtotal			
Contingency			

Escalation			
Baseline Capital Budget			
Regulatory			
Existing Meters			
Other Non-Project Costs			
Total Project Budget			

Table A17.1: Amended Summary of Capital Costs (add rows as required)

	2008	2009	2010	Total
	($000s)			
Meters and Modules				
SMI Vendor Training				
Network Infrastructure				
IT Infrastructure and Upgrades				
MDMR - Meter Data Management Repository				
VEE				
HAN				
Project Management				
Network Design and Testing				
AFUDC				
IDC				
Subtotal				
Contingency				
Escalation				
Baseline Capital Budget				
Regulatory				
Existing Meters				
Other Non-Project Costs				
Total Project Budget				

A54.2 The tables requested are provided below:

Table A54.29(a) - Amended Table 6.3: Summary of Capital Costs

	Costs	Costs
	Original CPCN Application	**Amended Application**
	($000s)	**($000s)**
(i) Meters and Modules	19,507	20,684
(ii) Network Infrastructure	6,700	7,771
(iii) IT Infrastructure and Upgrades	1,483	5,014
(iv) Project Management	2,701	2,701
AFUDC	950	1,130
Total Capital Cost	**31,341**	**37,300**
(v) Non-Project Costs		
Incremental Meter Costs	1,336	1,444
Avoided Future Capital Costs	(1,250)	(1,250)

1 **Table A54.2(b) - Amended Table A16.12: Capital Cost Summary**

	Direct Cost	**Indirect Cost**	**Total**
	($000s)		
Meters and Modules	16,086	1,175	17,261
AMI Vendor Training	35	3	38
Network Infrastructure	5,537	404	5,941
IT Infrastructure and Upgrades	994	72	1,066
MDMR - Meter Data Management Repository	260	18	278
VEE	2,986	217	3,203
HAN & Hourly Reading	2,358	159	2,517
Project Management	1,662	123	1,785
Network Design and Testing	561	40	601
AFUDC	-	1,056	1,056
IDC	NA	NA	NA
Subtotal	30,480	3,268	33,746
Contingency	2,583	181	2,764
Escalation	714	49	763
Baseline Capital Budget	3,297	230	**37,273**
Regulatory	25	-	25
Other Non-Project Costs	-	-	0
Total Project Budget	**33,802**	**3,498**	**37,300**
Existing Meters	8,900	0	8,900
In-Home Display	8,100	0	8,100
Total Project Budget plus Existing Meters & IHD	**50,802**	**3,498**	**54,300**

Note: HAN and Hourly Reading previously included in Meters and Modules and Network Infrastructure

Table A54.29(c) - Amended Table A17.1: Summary of Capital Costs

	2008	2009	2010	Total
	($000s)			
Meters and Modules	-	6,991	10,271	17,262
AMI Vendor Training	38	-	-	38
Network Infrastructure	-	3,003	2,939	5,942
IT Infrastructure and Upgrades	-	928	138	1,066
MDMR - Meter Data Management Repository	-	279	0	279
VEE	-	1,617	1,586	3,203
HAN & Hourly Reading	-	806	1,709	2,515
Project Management	445	358	982	1,785
Network Design and Testing	-	602	-	602
AFUDC	16	470	570	1,056
IDC	NA	NA	NA	NA
Subtotal	**499**	**15,052**	**18,196**	**33,748**
Contingency	49	1,217	1,498	2,764
Escalation	-	223	540	763
Baseline Capital Budget	**49**	**1,440**	**2,038**	**37,275**
Regulatory	25	-	-	25
Other Non-Project Costs				0
Total Project Budget	**573**	**16,492**	**20,234**	**37,300**
Existing Meters		3,200	5,700	8,900
In-Home Display	-	-	-	-
Total Project Budget plus Existing Meters	**573**	**19,692**	**25,934**	**46,200**

Note: HAN and Hourly Reading previously included in Meters and Modules and Network Infrastructure. In-home displays assumed post-2010.

55.0 Reference: Revision to Rate Impact Analysis
Exhibit B-6, p. 14, Amended Table 6.6

Q55.1 Please provide two additional rate impact analyses assuming the economic AND accounting life of the meters is 15 years (i.e., replacement required after 15 years), the economic life of the computer hardware is five years, and the economic life of the computer software is three years and using the base case assumptions in a) the original application and b) the amended application. Include the replacement costs for each component and include a terminal value at the end of 25 years for the remaining economic value of each component (e.g., there would be two meter replacements during the 25 year analysis period and five years of economic life remaining on the meters at the end of 25 years).

A55.1 Please see the rate impact analysis below labeled BCUC IR3 55.1a that reflects the Original Application and BCUC IR3 55.1b that reflects the Amended Application.

The Company has also included a third rate impact analysis labeled BCUC IR3 55.1c that it believes reflects the actual replacement cost of the meters, hardware and software over the 25 year analysis period based on the following assumptions:

Assuming a 15 year technological and economic life of the meters, FortisBC does not believe that it would replace the entire meter population at the end of the 15 years. Instead, because the AMI technology would be in place and operating, the Company would be able to stage the replacement over a longer period. In this analysis, the meters would be replaced over a 5 year period beginning in year 16.

In this analysis, the Company has assumed a 5 year technological and economic life of certain components of the hardware such as servers and data storage devices.

FortisBC does not consider a three year economic life for Computer Software to be appropriate for several reasons:

(iv) The software is a database that holds AMI reading data and performs estimates. Because much of the functionality is adaptable and rule-based, the system does not need to be fully replaced and can be easily enhanced to match any future business requirements.

(v) The AMI operating expenses contain software maintenance fees over the life of the project to account for upgrades to the software which will prolong the life and keep the software up to date.

(vi) Historically, FortisBC has not replaced major IT systems as frequently as every three years.

As an example, the Company uses as one of its core applications, an SAP application that provides financial, human resource, materials management and project management functionality. The current version has been used by the Company since 2002 and although the Company is upgrading the product in 2008, the decision to do so was not due to technological obsolescence, but due to other business drivers such as the adaptation of International Financial Reporting Standards by Canadian GAAP in 2011. In the absence of this external driver, the Company would have not made the decision to upgrade and would have been able to stay on the current version as long as it was supported by the vendor. Similarly, another of FortisBC's core applications is its Customer Information System that was implemented in 2000 and with annual upgrades is not expected to be replaced in the foreseeable future.

Therefore, in this example, the Company has assumed that the software will only be replaced every 10 years and at 25 percent of the escalated original installation cost.

Revenue Requirements Template

BCUC IR3 55.1a

Option "AMI"

Original Application

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
	Summary											
	Revenue Requirements											
1	Operating Expense (Incremental)	**(24,605)**	0	0	(516)	(2,377)	(2,497)	(2,624)	(2,746)	(2,883)	(3,026)	(3,174)
2	Depreciation Expense	**21,876**	0	0	1,333	2,535	2,540	2,086	2,539	3,063	3,067	2,565
3	Carrying Costs	**13,691**	0	530	1,658	2,164	1,980	1,869	1,821	1,681	1,456	1,312
4	Income Tax	**4,186**	0	(344)	(433)	(145)	40	36	352	649	720	603
5	Total Revenue Requirement for Project	**15,148**	0	186	2,043	2,177	2,063	1,366	1,967	2,509	2,217	1,305
6												
7												
8	**Rate Impact**											
9	Forecast Revenue Requirements	**3,042,076**	219,817	240,023	255,139	272,208	287,690	293,400	299,300	305,300	311,400	317,600
10	Rate Impact		0.00%	0.08%	0.80%	0.80%	0.72%	0.47%	0.66%	0.82%	0.71%	0.41%
11												
12	**NPV of Project / Total Revenue Requirements**	**0.50%**										
13												
14												
15	**Regulatory Assumptions**											
16	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
17	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
18	Equity Return		9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
19	Debt Return		6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
20	AFUDC		6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%
21												
22			568	14,208	17,339	79	61	1,580	1,775	61	60	1,701
23	**Capital Cost**		568	14,208	31,547	31,627	31,688	33,268	35,042	35,103	35,163	36,864
24	Capital Investment		551	13,120	16,720	0	0	0	0	0	0	0
25	Incremental meter costs		0	110	97	79	61	62	62	61	60	59
26	Avoided Itron Purchase (2013 & 2018)		0	0	0	0	0	(250)	0	0	0	0
27	AFUDC		17	410	523							
28	Total Construction Cost in Year		568	13,640	17,339	79	61	(188)	62	61	60	59
29	Cumulative Construction Cost		568	14,208	31,547	31,627	31,688	31,500	31,562	31,623	31,683	31,741
30	Land											
31	Net Cost of Removal											
32	Total Capital Cost in Year		568	13,640	17,339	79	61	(188)	62	61	60	59
33	Cumulative Capital Cost		568	14,208	31,547	31,627	31,688	31,500	31,562	31,623	31,683	31,741

10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Dec-18	**Dec-19**	**Dec-20**	**Dec-21**	**Dec-22**	**Dec-23**	**Dec-24**	**Dec-25**	**Dec-26**	**Dec-27**	**Dec-28**	**Dec-29**	**Dec-30**	**Dec-31**	**Dec-32**	**Dec-33**
(3,327)	(3,485)	(3,637)	(3,403)	(3,566)	(3,735)	(3,910)	(4,092)	(4,256)	(4,442)	(4,635)	(4,837)	(5,048)	(5,269)	(5,484)	(5,725)
2,601	3,163	3,170	2,626	2,664	3,272	3,275	2,258	1,906	4,168	4,123	3,483	3,570	4,281	4,283	3,591
1,247	1,105	880	734	674	524	291	830	2,402	3,166	2,859	2,664	2,568	2,357	2,040	1,749
691	949	968	790	836	1,077	1,073	818	990	1,983	1,934	1,682	1,707	1,941	1,892	1,597
1,212	1,732	1,381	747	607	1,137	728	(186)	1,041	4,875	4,281	2,992	2,797	3,310	2,731	1,212
324,000	330,500	337,100	343,800	350,700	357,700	364,900	372,200	379,600	387,200	394,900	402,800	410,900	419,100	427,500	436,100
0.37%	0.52%	0.41%	0.22%	0.17%	0.32%	0.20%	-0.05%	0.27%	1.26%	1.08%	0.74%	0.68%	0.79%	0.64%	0.28%
40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%
1,732	237	54	1,830	1,864	49	248	19,736	26,519	34	34	2,339	2,160	35	35	35
38,597	38,834	38,887	40,718	42,582	42,631	42,879	62,615	89,134	89,168	89,202	91,541	93,701	93,736	93,771	93,806
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
57	55	54	52	50	49	47	46	34	34	34	34	35	35	35	35
(250)	0	0	0	0	(250)	0	0	0	0	(250)	0	0	0	0	(250)
(193)	55	54	52	50	(201)	47	46	34	34	(216)	34	35	35	35	(215)
31,548	31,603	31,657	31,709	31,759	31,558	31,606	31,652	31,685	31,719	31,503	31,538	31,572	31,607	31,642	31,427
(193)	55	54	52	50	(201)	47	46	34	34	(216)	34	35	35	35	(215)
31,548	31,603	31,657	31,709	31,759	31,558	31,606	31,652	31,685	31,719	31,503	31,538	31,572	31,607	31,642	31,427

34		0	110	207	286	347	159	221	282	342	400
35	Additions to Plant in Service	0	14,208	17,339	79	61	(188)	62	61	60	59
36	Cummulative Additions to Plant	0	14,208	31,547	31,627	31,688	31,500	31,562	31,623	31,683	31,741
37	CWIP	568	0	0	0	0	0	0	0	0	0
38											
39											
40	**Annual Operating Costs / (Savings)**										
41	**Savings**										
42	Annual Meter Reading Savings	-	-	(592)	(2,491)	(2,610)	(2,736)	(2,856)	(2,992)	(3,132)	(3,279)
43	Annual Customer Service Savings	-	-	(71)	(295)	(303)	(312)	(320)	(329)	(338)	(347)
44	Annual Operations Savings	-	-	-	(318)	(329)	(340)	(351)	(363)	(375)	(387)
45	**Costs**										
46	Incremental Labour		-	148	296	304	314	323	333	343	353
47	Software Service Agreement		-	-	242	246	251	256	262	267	272
48	Communications		-	-	142	145	148	151	154	157	160
49	Equipment Replacements		-	-	48	49	50	51	52	53	54
50											
51	Total Incremental Operating Costs (Savings)	0	0	(516)	(2,377)	(2,497)	(2,624)	(2,746)	(2,883)	(3,026)	(3,174)
52											
53											
54											
55											
56	**Depreciation Expense**										
57	Opening Cash Outlay	0	0	14,208	31,547	31,627	31,688	33,268	35,042	35,103	35,163
58	Additions in Year	0	14,208	17,339	79	61	1,580	1,775	61	60	1,701
59	Cumulative Total	0	14,208	31,547	31,627	31,688	33,268	35,042	35,103	35,163	36,864
60	Depreciation Rate - composite average		0.00%	4.23%	8.01%	8.02%	6.27%	7.25%	8.73%	8.72%	6.96%
61	Depreciation Expense	0	0	1,333	2,535	2,540	2,086	2,539	3,063	3,067	2,565
62											
63	**Net Book Value - Total**										
64	Gross Property	0	14,208	31,547	31,626	31,688	33,267	35,042	35,103	35,163	36,864
65	Accumulated Depreciation	0	0	(1,333)	(3,868)	(6,408)	(8,493)	(11,032)	(14,095)	(17,162)	(19,727)
66	Net Book Value	0	14,208	30,214	27,759	25,280	24,774	24,010	21,008	18,001	17,137
67											
68											
69	**Depreciation Expense - Meters**										
70	Opening Cash Outlay	0	0	12,687	29,857	29,936	29,997	30,059	30,121	30,182	30,242
71	Additions in Year	0	12,687	17,169	79	61	62	62	61	60	59
72	Cumulative Total	0	12,687	29,857	29,936	29,997	30,059	30,121	30,182	30,242	30,300
73	Depreciation Rate - composite average	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
74	Depreciation Expense	0	0	846	1,990	1,996	2,000	2,004	2,008	2,012	2,016
75											
76	**Net Book Value - Meters**										
77	Gross Property	0	12,687	29,857	29,936	29,997	30,059	30,121	30,182	30,242	30,300
78	Accumulated Depreciation	0	0	(846)	(2,836)	(4,832)	(6,832)	(8,836)	(10,844)	(12,856)	(14,872)
79	Net Book Value	0	12,687	29,011	27,099	25,165	23,227	21,285	19,338	17,386	15,428
80											
81											

207	262	316	368	419	218	265	311	344	378	162	197	231	266	301	86
(193)	55	54	52	50	(201)	47	46	34	34	(216)	34	35	35	35	(215)
31,548	31,603	31,657	31,709	31,759	31,558	31,606	31,652	31,685	31,719	31,503	31,538	31,572	31,607	31,642	31,427
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(3,430)	(3,588)	(3,738)	(3,907)	(4,082)	(4,263)	(4,450)	(4,644)	(4,822)	(5,021)	(5,229)	(5,446)	(5,672)	(5,907)	(6,138)	(6,395)
(357)	(366)	(376)	(386)	(396)	(406)	(417)	(427)	(437)	(447)	(458)	(469)	(480)	(492)	(504)	(516)
(399)	(412)	(425)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(43)	(44)	(45)	(47)	(48)
364	374	386	397	409	421	434	447	460	474	489	503	518	534	550	566
278	283	289	295	300	306	313	319	325	332	338	345	352	359	366	374
163	166	170	173	176	180	184	187	191	195	199	203	207	211	215	219
55	57	58	59	60	61	62	64	65	66	68	69	70	72	73	75
(3,327)	(3,485)	(3,637)	(3,403)	(3,566)	(3,735)	(3,910)	(4,092)	(4,256)	(4,442)	(4,635)	(4,837)	(5,048)	(5,269)	(5,484)	(5,725)
36,864	38,597	38,834	38,887	40,718	42,582	42,631	42,879	62,615	89,134	89,168	89,202	91,541	93,701	93,736	93,771
1,732	237	54	1,830	1,864	49	248	19,736	26,519	34	34	2,339	2,160	35	35	35
38,597	38,834	38,887	40,718	42,582	42,631	42,879	62,615	89,134	89,168	89,202	91,541	93,701	93,736	93,771	93,806
6.74%	8.14%	8.15%	6.45%	6.26%	7.67%	7.64%	3.61%	2.14%	4.67%	4.62%	3.81%	3.81%	4.57%	4.57%	3.83%
2,601	3,163	3,170	2,626	2,664	3,272	3,275	2,258	1,906	4,168	4,123	3,483	3,570	4,281	4,283	3,591
38,597	38,834	38,887	40,718	42,582	42,631	42,879	62,615	89,134	89,168	89,202	91,541	93,701	93,736	93,771	93,806
(22,328)	(25,491)	(28,661)	(31,287)	(33,950)	(37,222)	(40,497)	(42,755)	(44,660)	(48,829)	(52,951)	(56,435)	(60,005)	(64,286)	(68,569)	(72,160)
16,269	13,343	10,227	9,431	8,632	5,409	2,382	19,860	44,474	40,339	36,251	35,107	33,696	29,450	25,202	21,646
30,300	30,357	30,412	30,466	30,518	30,569	30,618	30,665	48,476	73,032	73,066	73,100	73,134	73,169	73,203	73,238
57	55	54	52	50	49	47	17,811	24,556	34	34	34	35	35	35	35
30,357	30,412	30,466	30,518	30,569	30,618	30,665	48,476	73,032	73,066	73,100	73,134	73,169	73,203	73,238	73,274
6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
2,020	2,024	2,027	2,031	2,035	2,038	2,041	1,577	1,187	2,824	2,827	2,829	2,831	2,834	2,836	2,838
30,357	30,412	30,466	30,518	30,569	30,618	30,665	48,476	73,032	73,066	73,100	73,134	73,169	73,203	73,238	73,274
(16,892)	(18,916)	(20,943)	(22,974)	(25,009)	(27,047)	(29,088)	(30,665)	(31,852)	(34,677)	(37,503)	(40,332)	(43,164)	(45,997)	(48,833)	(51,671)
13,465	11,497	9,523	7,544	5,560	3,571	1,577	17,811	41,180	38,389	35,596	32,802	30,005	27,206	24,405	21,602

82	**Depreciation Expense - Computer Hardware**										
83	Opening Cash Outlay	0	0	146	146	146	146	146	311	311	311
84	Additions in Year	0	146	0	0	0	0	165	0	0	0
85	Cumulative Total	0	146	146	146	146	146	311	311	311	311
86	Depreciation Rate - composite average	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
87	Depreciation Expense	0	0	29	29	29	29	29	33	33	33
88											
89	**Net Book Value - Computer Hardware**										
90	Gross Property	0	146	146	146	146	146	311	311	311	311
91	Accumulated Depreciation	0	0	(29)	(58)	(88)	(117)	(146)	(179)	(212)	(245)
92	Net Book Value	0	146	117	88	58	29	165	132	99	66
93											
94											
95	**Depreciation Expense - Computer Software**										
96	Opening Cash Outlay	0	0	1,375	1,545	1,545	1,545	3,062	4,610	4,610	4,610
97	Additions in Year	0	1,375	170	0	0	1,518	1,548	0	0	1,643
98	Cumulative Total	0	1,375	1,545	1,545	1,545	3,062	4,610	4,610	4,610	6,253
99	Depreciation Rate - composite average	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%
100	Depreciation Expense	0	0	458	515	515	57	506	1,022	1,022	516
101											
102	**Net Book Value - Computer Software**										
103	Gross Property	0	1,375	1,545	1,545	1,545	3,062	4,610	4,610	4,610	6,253
104	Accumulated Depreciation	0	0	(458)	(973)	(1,488)	(1,545)	(2,051)	(3,073)	(4,094)	(4,610)
105	Net Book Value	0	1,375	1,086	572	57	1,518	2,560	1,538	516	1,643
106											
107	**Carrying Costs on Average NBV**										
108	Return on Equity	0	256	801	1,046	957	903	880	812	704	634
109	Interest Expense	0	274	857	1,118	1,023	966	941	868	752	678
110	AFUDC	0	0	0	0	0	0	0	0	0	0
111	**Total Carrying Costs**	0	530	1,658	2,164	1,980	1,869	1,821	1,681	1,456	1,312
112											
113											
114	**Income Tax Expense**										
115	Combined Income Tax Rate	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
116											
117	**Income Tax on Equity Return**										
118	Return on Equity	0	256	801	1,046	957	903	880	812	704	634
119	Gross up for revenue (Return / (1- tax rate)	0	371	1,145	1,463	1,311	1,237	1,206	1,112	964	868
120	Income tax on Equity Return	0	115	343	417	354	334	326	300	260	234
121											
122	**Income Tax on Timing Differences**										
123	Depreciation Expense	0	0	1,333	2,535	2,540	2,086	2,539	3,063	3,067	2,565
124	Less: Capital Cost Allowance	0	1,022	3,144	3,945	3,388	2,891	2,466	2,120	1,824	1,570
125	Total Timing Differences	0	(1,022)	(1,811)	(1,410)	(848)	(805)	73	943	1,243	995

311	311	492	492	492	492	492	693	693	693	693	693	915	915	915	915
0	182	0	0	0	0	201	0	0	0	0	222	0	0	0	0
311	492	492	492	492	492	693	693	693	693	693	915	915	915	915	915
20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
33	33	36	36	36	36	36	76	76	48	0	0	44	44	44	44
311	492	492	492	492	492	693	693	693	693	693	915	915	915	915	915
(278)	(311)	(347)	(383)	(420)	(456)	(492)	(569)	(645)	(693)	(693)	(693)	(737)	(782)	(826)	(870)
33	182	145	109	73	36	201	124	48	0	0	222	177	133	89	44
6,253	7,929	7,929	7,929	9,707	11,521	11,521	11,521	13,446	15,409	15,409	15,409	17,493	19,618	19,618	19,618
1,676	0	0	1,778	1,814	0	0	1,925	1,963	0	0	2,084	2,125	0	0	0
7,929	7,929	7,929	9,707	11,521	11,521	11,521	13,446	15,409	15,409	15,409	17,493	19,618	19,618	19,618	19,618
33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%
548	1,106	1,106	559	593	1,197	1,197	605	642	1,296	1,296	654	695	1,403	1,403	708
7,929	7,929	7,929	9,707	11,521	11,521	11,521	13,446	15,409	15,409	15,409	17,493	19,618	19,618	19,618	19,618
(5,158)	(6,264)	(7,370)	(7,929)	(8,522)	(9,719)	(10,917)	(11,521)	(12,163)	(13,459)	(14,755)	(15,409)	(16,104)	(17,507)	(18,910)	(19,618)
2,771	1,665	559	1,778	2,999	1,802	605	1,925	3,247	1,951	654	2,084	3,514	2,111	708	0
603	534	425	355	326	253	141	401	1,161	1,530	1,382	1,287	1,241	1,139	986	845
644	571	455	379	348	271	150	429	1,241	1,636	1,477	1,376	1,327	1,218	1,054	904
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1,247	1,105	880	734	674	524	291	830	2,402	3,166	2,859	2,664	2,568	2,357	2,040	1,749
27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
603	534	425	355	326	253	141	401	1,161	1,530	1,382	1,287	1,241	1,139	986	845
826	732	582	486	446	347	193	550	1,590	2,096	1,893	1,763	1,700	1,560	1,351	1,158
223	198	157	131	121	94	52	148	429	566	511	476	459	421	365	313
2,601	3,163	3,170	2,626	2,664	3,272	3,275	2,258	1,906	4,168	4,123	3,483	3,570	4,281	4,283	3,591
1,334	1,132	977	844	730	614	515	448	389	338	276	223	196	173	153	118
1,266	2,030	2,193	1,782	1,933	2,657	2,760	1,810	1,517	3,830	3,847	3,260	3,374	4,108	4,130	3,473

126	Gross up for tax (Total Timing Differences/(1-tax rate))	0	(1,481)	(2,587)	(1,973)	(1,161)	(1,103)	100	1,292	1,703	1,363
127	Income tax on Timing Differences	0	(459)	(776)	(562)	(314)	(298)	27	349	460	368
128											
129	**Total Income Tax**	0	(344)	(433)	(145)	40	36	352	649	720	603
130											
131											
132	**Capital Cost Allowance**										
133	Opening Balance - UCC	0	0	13,186	27,381	23,515	20,189	17,110	14,706	12,647	10,883
134	Additions	0	14,208	17,339	79	61	(188)	62	61	60	59
135	Subtotal UCC	0	14,208	30,525	27,460	23,576	20,001	17,172	14,767	12,706	10,941
136	Capital Cost Allowance Rate	14.39%	14.39%	14.39%	14.39%	14.39%	14.39%	14.39%	14.39%	14.39%	14.39%
137	CCA on Opening Balance	0	0	1,897	3,939	3,383	2,905	2,462	2,116	1,819	1,566
138	CCA on Capital Expenditures (1/2 yr rule)	0	1,022	1,247	6	4	(14)	4	4	4	4
139	Total CCA	0	1,022	3,144	3,945	3,388	2,891	2,466	2,120	1,824	1,570
140	Ending Balance UCC	0	13,186	27,381	23,515	20,189	17,110	14,706	12,647	10,883	9,371

1,735	2,781	3,004	2,441	2,648	3,640	3,781	2,480	2,078	5,247	5,269	4,466	4,622	5,627	5,658	4,757
468	751	811	659	715	983	1,021	670	561	1,417	1,423	1,206	1,248	1,519	1,528	1,284
691	949	968	790	836	1,077	1,073	818	990	1,983	1,934	1,682	1,707	1,941	1,892	1,597
9,371	7,844	6,767	5,843	5,051	4,371	3,555	3,088	2,686	2,331	2,027	1,535	1,346	1,184	1,046	928
(193)	55	54	52	50	(201)	47	46	34	34	(216)	34	35	35	35	(215)
9,178	7,899	6,820	5,895	5,101	4,170	3,603	3,134	2,720	2,365	1,811	1,569	1,380	1,219	1,081	713
14.39%	14.39%	14.39%	14.39%	14.39%	14.39%	14.39%	14.39%	14.39%	14.39%	14.39%	14.39%	14.39%	14.39%	14.39%	14.39%
1,348	1,128	974	841	727	629	512	444	386	335	292	221	194	170	151	134
(14)	4	4	4	4	(14)	3	3	2	2	(16)	2	2	3	3	(15)
1,334	1,132	977	844	730	614	515	448	389	338	276	223	196	173	153	118
7,844	6,767	5,843	5,051	4,371	3,555	3,088	2,686	2,331	2,027	1,535	1,346	1,184	1,046	928	595

Revenue Requirements
Option "AMI"
Amended Application

BCUC IR3 55.1b

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
	Summary												
	Revenue Requirements												
1	Operating Expense (Incremental)	**(24,542)**	0	0	(516)	(2,369)	(2,490)	(2,616)	(2,738)	(2,875)	(3,018)	(3,166)	(3,318)
2	Depreciation Expense	**32,302**	0	0	2,059	3,974	3,979	2,864	3,405	4,674	4,678	3,446	3,527
3	Carrying Costs	**16,091**	0	641	1,964	2,501	2,209	2,097	2,153	2,003	1,659	1,510	1,556
4	Income Tax	**6,878**	0	(490)	(524)	(9)	251	86	520	1,142	1,232	876	1,027
5	Total Revenue Requirement for Project	**30,729**	0	151	2,984	4,097	3,950	2,431	3,340	4,943	4,551	2,666	2,792
6													
7													
8	**Rate Impact**												
9	Forecast Revenue Requirements	**3,042,076**	219,817	240,023	255,139	272,208	287,690	293,400	299,300	305,300	311,400	317,600	324,000
10	Rate Impact		0.00%	0.06%	1.17%	1.51%	1.37%	0.83%	1.12%	1.62%	1.46%	0.84%	0.86%
11													
12	**NPV of Project / Total Revenue Requirements**	**1.01%**											
13													
14													
15	**Regulatory Assumptions**												
16	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
17	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
18	Equity Return		9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
19	Debt Return		6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
20	AFUDC		6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%
21													
22					20,337	79	61	3,770	4,005	61	60	4,072	4,150
23	**Capital Cost**		568	17,170	37,507	37,586	37,647	41,417	45,422	45,483	45,543	49,615	53,765
24	Capital Investment		551	15,992	19,627		0	0	0	0	0	0	0
25	Incremental meter costs		0	110	97	79	61	62	62	61	60	59	57
26	Avoided Itron Purchase (2013 & 2018)		0	0	0	0	0	(250)	0	0	0	0	(250)
27	AFUDC		17	500	613								
28	Total Construction Cost in Year		568	16,602	20,337	79	61	(188)	62	61	60	59	(193)
29	Cumulative Construction Cost		568	17,170	37,507	37,586	37,647	37,459	37,521	37,583	37,642	37,701	37,507
30	Land												
31	Net Cost of Removal												
32	Total Capital Cost in Year		568	16,602	20,337	79	61	(188)	62	61	60	59	(193)
33	Cumulative Capital Cost		568	17,170	37,507	37,586	37,647	37,459	37,521	37,583	37,642	37,701	37,507
34			0	110	207	286	347	159	221	282	342	400	207

11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Dec-19	**Dec-20**	**Dec-21**	**Dec-22**	**Dec-23**	**Dec-24**	**Dec-25**	**Dec-26**	**Dec-27**	**Dec-28**	**Dec-29**	**Dec-30**	**Dec-31**	**Dec-32**	**Dec-33**
(3,477)	(3,628)	(3,394)	(3,557)	(3,726)	(3,901)	(4,083)	(4,246)	(4,431)	(4,625)	(4,827)	(5,038)	(5,258)	(5,473)	(5,714)
4,895	4,935	3,600	3,662	5,100	5,142	3,203	2,924	6,262	6,264	4,661	4,765	6,498	6,500	4,806
1,406	1,049	897	957	807	442	1,032	2,847	3,659	3,194	2,986	3,029	2,805	2,322	2,109
1,601	1,624	1,163	1,247	1,802	1,795	1,210	1,455	2,855	2,797	2,187	2,243	2,851	2,773	2,121
4,425	3,980	2,267	2,310	3,982	3,478	1,363	2,981	8,344	7,630	5,007	4,999	6,896	6,122	3,321
330,500	337,100	343,800	350,700	357,700	364,900	372,200	379,600	387,200	394,900	402,800	410,900	419,100	427,500	436,100
1.34%	1.18%	0.66%	0.66%	1.11%	0.95%	0.37%	0.79%	2.15%	1.93%	1.24%	1.22%	1.65%	1.43%	0.76%
40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%
234	54	4,396	4,481	242	244	23,887	30,882	34	34	5,341	5,226	35	35	5,544
53,999	54,052	58,449	62,930	63,172	63,416	87,303	118,185	118,219	118,253	123,594	128,820	128,855	128,890	134,435
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55	54	52	50	49	47	46	34	34	34	34	35	35	35	35
0	0	0	0	(250)	0	0	0	0	(250)	0	0	0	0	(250)
55	54	52	50	(201)	47	46	34	34	(216)	34	35	35	35	(215)
37,563	37,616	37,669	37,719	37,518	37,565	37,611	37,645	37,679	37,463	37,497	37,532	37,566	37,601	37,387
55	54	52	50	(201)	47	46	34	34	(216)	34	35	35	35	(215)
37,563	37,616	37,669	37,719	37,518	37,565	37,611	37,645	37,679	37,463	37,497	37,532	37,566	37,601	37,387
262	316	368	419	218	265	311	344	378	162	197	231	266	301	86

35	Additions to Plant in Service	0	17,170	20,337	79	61	(188)	62	61	60	59	(193)
36	Cummulative Additions to Plant	0	17,170	37,507	37,586	37,647	37,459	37,521	37,583	37,642	37,701	37,507
37	CWIP	568	0	0	0	0	0	0	0	0	0	0
38												
39												
40	**Annual Operating Costs / (Savings)**											
41	**Savings**											
42	Annual Meter Reading Savings	-	-	(592)	(2,491)	(2,610)	(2,736)	(2,856)	(2,992)	(3,132)	(3,279)	(3,430)
43	Annual Customer Service Savings	-	-	(71)	(295)	(303)	(312)	(320)	(329)	(338)	(347)	(357)
44	Annual Operations Savings	-	-	-	(318)	(329)	(340)	(351)	(363)	(375)	(387)	(399)
45	**Costs**											
46	Incremental Labour		-	148	296	304	314	323	333	343	353	364
47	Software Service Agreement		-	-	242	246	251	256	262	267	272	278
48	Communications		-	-	142	145	148	151	154	157	160	163
49	Equipment Replacements		-	-	56	57	58	59	60	61	63	64
50												
51	Total Incremental Operating Costs (Savings)	0	0	(516)	(2,369)	(2,490)	(2,616)	(2,738)	(2,875)	(3,018)	(3,166)	(3,318)
52												
53												
54												
55												
56	**Depreciation Expense**											
57	Opening Cash Outlay											
58	Additions in Year											
59	Cumulative Total											
60	Depreciation Rate - composite average											
61	Depreciation Expense											
62												
63	**Net Book Value**											
64	Gross Property	0	17,170	37,507	37,586	37,647	41,417	45,422	45,483	45,543	49,615	53,765
65	Accumulated Depreciation	0	0	(2,059)	(6,033)	(10,013)	(12,877)	(16,282)	(20,956)	(25,634)	(29,080)	(32,606)
66	Net Book Value	0	17,170	35,448	31,553	27,634	28,540	29,140	24,527	19,909	20,535	21,158
67												
68												
69	**Depreciation Expense - Meters**											
70	Opening Cash Outlay	0	0	13,668	31,909	31,988	32,049	32,111	32,173	32,234	32,294	32,353
71	Additions in Year	0	13,668	18,241	79	61	62	62	61	60	59	57
72	Cumulative Total	0	13,668	31,909	31,988	32,049	32,111	32,173	32,234	32,294	32,353	32,409
73	Depreciation Rate - composite average	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
74	Depreciation Expense	0	0	911	2,127	2,133	2,137	2,141	2,145	2,149	2,153	2,157
75												
76	**Net Book Value - Meters**											
77	Gross Property	0	13,668	31,909	31,988	32,049	32,111	32,173	32,234	32,294	32,353	32,409
78	Accumulated Depreciation	0	0	(911)	(3,038)	(5,171)	(7,308)	(9,448)	(11,593)	(13,742)	(15,895)	(18,052)
79	Net Book Value	0	13,668	30,998	28,949	26,878	24,804	22,725	20,641	18,552	16,457	14,357
80												
81												

55	54	52	50	(201)	47	46	34	34	(216)	34	35	35	35	(215)
37,563	37,616	37,669	37,719	37,518	37,565	37,611	37,645	37,679	37,463	37,497	37,532	37,566	37,601	37,387
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(3,588)	(3,738)	(3,907)	(4,082)	(4,263)	(4,450)	(4,644)	(4,822)	(5,021)	(5,229)	(5,446)	(5,672)	(5,907)	(6,138)	(6,395)
(366)	(376)	(386)	(396)	(406)	(417)	(427)	(437)	(447)	(458)	(469)	(480)	(492)	(504)	(516)
(412)	(425)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(43)	(44)	(45)	(47)	(48)
374	386	397	409	421	434	447	460	474	489	503	518	534	550	566
283	289	295	300	306	313	319	325	332	338	345	352	359	366	374
166	170	173	176	180	184	187	191	195	199	203	207	211	215	219
65	67	68	69	71	72	73	75	76	78	80	81	83	84	86
(3,477)	(3,628)	(3,394)	(3,557)	(3,726)	(3,901)	(4,083)	(4,246)	(4,431)	(4,625)	(4,827)	(5,038)	(5,258)	(5,473)	(5,714)
53,999	54,052	58,449	62,930	63,172	63,416	87,303	118,185	118,219	118,253	123,594	128,820	128,855	128,890	134,435
(37,502)	(42,436)	(46,036)	(49,698)	(54,798)	(59,939)	(63,143)	(66,067)	(72,329)	(78,594)	(83,254)	(88,019)	(94,517)	(101,017)	(105,823)
16,497	11,616	12,412	13,232	8,374	3,477	24,161	52,118	45,890	39,659	40,340	40,801	34,338	27,873	28,612
32,409	32,465	32,518	32,570	32,621	32,670	32,717	51,902	77,988	78,022	78,056	78,090	78,124	78,159	78,194
55	54	52	50	49	47	19,185	26,086	34	34	34	35	35	35	35
32,465	32,518	32,570	32,621	32,670	32,717	51,902	77,988	78,022	78,056	78,090	78,124	78,159	78,194	78,229
6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
2,161	2,164	2,168	2,171	2,175	2,178	1,648	1,279	3,018	3,020	3,023	3,025	3,027	3,029	3,032
32,465	32,518	32,570	32,621	32,670	32,717	51,902	77,988	78,022	78,056	78,090	78,124	78,159	78,194	78,229
(20,213)	(22,377)	(24,545)	(26,716)	(28,891)	(31,069)	(32,717)	(33,996)	(37,014)	(40,034)	(43,057)	(46,082)	(49,109)	(52,138)	(55,170)
12,252	10,141	8,026	5,905	3,779	1,648	19,185	43,992	41,007	38,021	35,033	32,043	29,050	26,056	23,059

82	**Depreciation Expense - Computer Hardware**											
83	Opening Cash Outlay	0	0	143	143	143	143	143	305	305	305	305
84	Additions in Year	0	143	0	0	0	0	162	0	0	0	0
85	Cumulative Total	0	143	143	143	143	143	305	305	305	305	305
86	Depreciation Rate - composite average	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
87	Depreciation Expense	0	0	29	29	29	29	29	32	32	32	32
88												
89	**Net Book Value - Computer Hardware**											
90	Gross Property	0	143	143	143	143	143	305	305	305	305	305
91	Accumulated Depreciation	0	0	(29)	(57)	(86)	(115)	(143)	(176)	(208)	(240)	(273)
92	Net Book Value	0	143	115	86	57	29	162	129	97	65	32
93												
94												
95	**Depreciation Expense - Computer Software**											
96	Opening Cash Outlay	0	0	3,358	5,455	5,455	5,455	9,162	12,944	12,944	12,944	16,957
97	Additions in Year	0	3,358	2,097	0	0	3,708	3,782	0	0	4,013	4,093
98	Cumulative Total	0	3,358	5,455	5,455	5,455	9,162	12,944	12,944	12,944	16,957	21,051
99	Depreciation Rate - composite average	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%
100	Depreciation Expense	0	0	1,119	1,818	1,818	699	1,236	2,496	2,496	1,261	1,338
101												
102	**Net Book Value - Computer Software**											
103	Gross Property	0	3,358	5,455	5,455	5,455	9,162	12,944	12,944	12,944	16,957	21,051
104	Accumulated Depreciation	0	0	(1,119)	(2,938)	(4,756)	(5,455)	(6,691)	(9,187)	(11,684)	(12,944)	(14,282)
105	Net Book Value	0	3,358	4,335	2,517	699	3,708	6,253	3,757	1,261	4,013	6,769
106												
107	**Carrying Costs on Average NBV**											
108	Return on Equity	0	310	949	1,209	1,068	1,013	1,041	968	802	730	752
109	Interest Expense	0	331	1,015	1,292	1,142	1,084	1,113	1,035	857	780	804
110	AFUDC	0	0	0	0	0	0	0	0	0	0	0
111	**Total Carrying Costs**	0	641	1,964	2,501	2,209	2,097	2,153	2,003	1,659	1,510	1,556
112												
113												
114	**Income Tax Expense**											
115	Combined Income Tax Rate	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
116												
117	**Income Tax on Equity Return**											
118	Return on Equity	0	310	949	1,209	1,068	1,013	1,041	968	802	730	752
119	Gross up for revenue (Return / (1- tax rate)	0	449	1,356	1,690	1,463	1,388	1,425	1,326	1,098	999	1,030
120	Income tax on Equity Return	0	139	407	482	395	375	385	358	296	270	278
121												
122	**Income Tax on Timing Differences**											
123	Depreciation Expense	0	0	2,059	3,974	3,979	2,864	3,405	4,674	4,678	3,446	3,527
124	Less: Capital Cost Allowance	0	1,400	4,231	5,206	4,368	3,645	3,040	2,555	2,148	1,807	1,501
125	Total Timing Differences	0	(1,400)	(2,172)	(1,232)	(389)	(781)	365	2,119	2,530	1,639	2,026
126	Gross up for tax (Total Timing Differences/(1-tax rate))	0	(2,030)	(3,103)	(1,723)	(533)	(1,070)	500	2,903	3,466	2,245	2,775
127	Income tax on Timing Differences	0	(629)	(931)	(491)	(144)	(289)	135	784	936	606	749

305	483	483	483	483	677	874	874	874	874	874	1,091	1,091	1,091	1,091
178	0	0	0	193	197	0	0	0	0	217	0	0	0	0
483	483	483	483	677	874	874	874	874	874	1,091	1,091	1,091	1,091	1,091
20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
32	68	68	42	0	39	78	78	78	78	39	43	43	43	43

483	483	483	483	676	873	873	873	873	873	1,091	1,091	1,091	1,091	1,091
(305)	(373)	(441)	(483)	(483)	(522)	(600)	(678)	(756)	(834)	(873)	(917)	(960)	(1,004)	(1,047)
178	110	42	0	193	351	273	195	117	39	217	174	130	87	43

21,051	21,051	21,051	25,395	29,826	29,826	29,826	34,528	39,324	39,324	39,324	44,413	49,605	49,605	49,605
0	0	4,344	4,431	0	0	4,702	4,796	0	0	5,090	5,191	0	0	5,509
21,051	21,051	25,395	29,826	29,826	29,826	34,528	39,324	39,324	39,324	44,413	49,605	49,605	49,605	55,114
33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%
2,702	2,702	1,364	1,448	2,925	2,925	1,477	1,567	3,166	3,166	1,599	1,697	3,427	3,427	1,730

21,051	21,051	25,395	29,826	29,826	29,826	34,528	39,324	39,324	39,324	44,413	49,605	49,605	49,605	55,114
(16,984)	(19,686)	(21,051)	(22,499)	(25,424)	(28,349)	(29,826)	(31,393)	(34,559)	(37,725)	(39,324)	(41,020)	(44,447)	(47,874)	(49,605)
4,067	1,364	4,344	7,327	4,402	1,477	4,702	7,931	4,765	1,599	5,090	8,585	5,158	1,730	5,509

679	507	433	463	390	214	499	1,376	1,768	1,543	1,443	1,464	1,356	1,122	1,019
726	542	464	495	417	229	533	1,471	1,891	1,650	1,543	1,565	1,449	1,200	1,090
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1,406	1,049	897	957	807	442	1,032	2,847	3,659	3,194	2,986	3,029	2,805	2,322	2,109

27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%

679	507	433	463	390	214	499	1,376	1,768	1,543	1,443	1,464	1,356	1,122	1,019
931	695	594	634	534	293	683	1,885	2,422	2,114	1,977	2,005	1,857	1,537	1,396
251	188	160	171	144	79	184	509	654	571	534	541	501	415	377

4,895	4,935	3,600	3,662	5,100	5,142	3,203	2,924	6,262	6,264	4,661	4,765	6,498	6,500	4,806
1,245	1,051	888	752	617	504	429	366	311	246	191	165	144	126	91
3,650	3,884	2,712	2,910	4,483	4,638	2,774	2,559	5,951	6,019	4,470	4,600	6,354	6,374	4,715
5,000	5,320	3,715	3,987	6,141	6,353	3,800	3,505	8,152	8,245	6,123	6,301	8,704	8,731	6,459
1,350	1,436	1,003	1,076	1,658	1,715	1,026	946	2,201	2,226	1,653	1,701	2,350	2,357	1,744

128												
129	**Total Income Tax**	0	(490)	(524)	(9)	251	86	520	1,142	1,232	876	1,027
130												
131												
132	**Capital Cost Allowance**											
133	Opening Balance - UCC	0	0	15,769	31,876	26,748	22,441	18,608	15,629	13,136	11,048	9,300
134	Additions	0	17,170	20,337	79	61	(188)	62	61	60	59	(193)
135	Subtotal UCC	0	17,170	36,107	31,955	26,810	22,253	18,670	15,691	13,196	11,107	9,106
136	Capital Cost Allowance Rate	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%
137	CCA on Opening Balance	0	0	2,572	5,200	4,363	3,661	3,035	2,550	2,143	1,802	1,517
138	CCA on Capital Expenditures (1/2 yr rule)	0	1,400	1,659	6	5	(15)	5	5	5	5	(16)
139	Total CCA	0	1,400	4,231	5,206	4,368	3,645	3,040	2,555	2,148	1,807	1,501
140	Ending Balance UCC	0	15,769	31,876	26,748	22,441	18,608	15,629	13,136	11,048	9,300	7,605

1,601	1,624	1,163	1,247	1,802	1,795	1,210	1,455	2,855	2,797	2,187	2,243	2,851	2,773	2,121
7,605	6,415	5,418	4,582	3,881	3,063	2,607	2,224	1,892	1,614	1,153	996	865	756	665
55	54	52	50	(201)	47	46	34	34	(216)	34	35	35	35	(215)
7,660	6,469	5,470	4,633	3,680	3,111	2,653	2,258	1,926	1,399	1,187	1,031	900	791	450
16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%
1,241	1,047	884	747	633	500	425	363	309	263	188	163	141	123	108
5	4	4	4	(16)	4	4	3	3	(18)	3	3	3	3	(18)
1,245	1,051	888	752	617	504	429	366	311	246	191	165	144	126	91
6,415	5,418	4,582	3,881	3,063	2,607	2,224	1,892	1,614	1,153	996	865	756	665	359

Revenue Requirements
Option "AMI"
Amended Application

BCUC IR3 55.1c

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
	Summary												
	Revenue Requirements												
1	Operating Expense (Incremental)	**(24,542)**	0	0	(516)	(2,369)	(2,490)	(2,616)	(2,738)	(2,875)	(3,018)	(3,166)	(3,318)
2	Depreciation Expense	**20,411**	0	0	1,276	2,701	2,707	2,711	2,715	2,723	2,727	2,731	2,735
3	Carrying Costs	**14,812**	0	641	1,993	2,607	2,410	2,213	2,021	1,829	1,630	1,430	1,269
4	Income Tax	**2,187**	0	(490)	(854)	(496)	(184)	50	241	389	505	597	683
5	Total Revenue Requirement for Project	**12,869**	0	151	1,900	2,443	2,444	2,357	2,239	2,065	1,844	1,593	1,368
6													
7													
8	**Rate Impact**												
9	Forecast Revenue Requirements	**3,042,076**	219,817	240,023	255,139	272,208	287,690	293,400	299,300	305,300	311,400	317,600	324,000
10	Rate Impact		0.00%	0.06%	0.74%	0.90%	0.85%	0.80%	0.75%	0.68%	0.59%	0.50%	0.42%
11													
12	**NPV of Project / Total Revenue Requirements**	**0.42%**											
13													
14													
15	**Regulatory Assumptions**												
16	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
17	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
18	Equity Return		9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
19	Debt Return		6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
20	AFUDC		6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%
21													
22					20,337	79	61	62	223	61	60	59	1,080
23	**Capital Cost**	Do Not Use	568	17,170	37,507	37,586	37,647	37,709	37,933	37,994	38,054	38,112	39,192
24	Capital Investment		551	15,992	19,627		0	0	0	0	0	0	0
25	Incremental meter costs		0	110	97	79	61	62	62	61	60	59	57
26	Avoided Itron Purchase (2013 & 2018)		0	0	0	0	0	(250)	0	0	0	0	(250)
27	AFUDC		17	500	613								
28	Total Construction Cost in Year		568	16,602	20,337	79	61	(188)	62	61	60	59	(193)
29	Cumulative Construction Cost		568	17,170	37,507	37,586	37,647	37,459	37,521	37,583	37,642	37,701	37,507
30	Land												
31	Net Cost of Removal												
32	Total Capital Cost in Year		568	16,602	20,337	79	61	(188)	62	61	60	59	(193)
33	Cumulative Capital Cost		568	17,170	37,507	37,586	37,647	37,459	37,521	37,583	37,642	37,701	37,507
34			0	110	207	286	347	159	221	282	342	400	207

11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Dec-19	**Dec-20**	**Dec-21**	**Dec-22**	**Dec-23**	**Dec-24**	**Dec-25**	**Dec-26**	**Dec-27**	**Dec-28**	**Dec-29**	**Dec-30**	**Dec-31**	**Dec-32**	**Dec-33**
(3,477)	(3,628)	(3,394)	(3,557)	(3,726)	(3,901)	(4,083)	(4,246)	(4,431)	(4,625)	(4,827)	(5,038)	(5,258)	(5,473)	(5,714)
2,841	2,985	2,988	2,884	2,175	2,217	1,726	677	1,287	2,031	2,752	3,403	3,405	3,408	3,410
1,149	981	762	547	369	223	420	1,007	1,669	2,341	2,935	3,077	2,826	2,574	2,322
796	891	913	886	642	673	555	295	659	1,079	1,472	1,747	1,711	1,674	1,643
1,308	1,228	1,269	760	(540)	(788)	(1,381)	(2,267)	(816)	827	2,332	3,190	2,684	2,182	1,661
330,500	337,100	343,800	350,700	357,700	364,900	372,200	379,600	387,200	394,900	402,800	410,900	419,100	427,500	436,100
0.40%	0.36%	0.37%	0.22%	-0.15%	-0.22%	-0.37%	-0.60%	-0.21%	0.21%	0.58%	0.78%	0.64%	0.51%	0.38%
40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%
1,278	54	52	50	242	244	8,982	9,148	10,554	10,765	9,924	35	35	35	35
40,470	40,524	40,576	40,626	40,868	41,113	50,095	59,243	69,797	80,561	90,486	90,520	90,555	90,590	90,625
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55	54	52	50	49	47	46	34	34	34	34	35	35	35	35
0	0	0	0	(250)	0	0	0	0	(250)	0	0	0	0	(250)
55	54	52	50	(201)	47	46	34	34	(216)	34	35	35	35	(215)
37,563	37,616	37,669	37,719	37,518	37,565	37,611	37,645	37,679	37,463	37,497	37,532	37,566	37,601	37,387
55	54	52	50	(201)	47	46	34	34	(216)	34	35	35	35	(215)
37,563	37,616	37,669	37,719	37,518	37,565	37,611	37,645	37,679	37,463	37,497	37,532	37,566	37,601	37,387
262	316	368	419	218	265	311	344	378	162	197	231	266	301	86

35	Additions to Plant in Service	0	17,170	20,337	79	61	(188)	62	61	60	59	(193)
36	Cummulative Additions to Plant	0	17,170	37,507	37,586	37,647	37,459	37,521	37,583	37,642	37,701	37,507
37	CWIP	568	0	0	0	0	0	0	0	0	0	0
38												
39												
40	**Annual Operating Costs / (Savings)**											
41	**Savings**											
42	Annual Meter Reading Savings	-	-	(592)	(2,491)	(2,610)	(2,736)	(2,856)	(2,992)	(3,132)	(3,279)	(3,430)
43	Annual Customer Service Savings	-	-	(71)	(295)	(303)	(312)	(320)	(329)	(338)	(347)	(357)
44	Annual Operations Savings	-	-	-	(318)	(329)	(340)	(351)	(363)	(375)	(387)	(399)
45	**Costs**											
46	Incremental Labour		-	148	296	304	314	323	333	343	353	364
47	Software Service Agreement		-	-	242	246	251	256	262	267	272	278
48	Communications		-	-	142	145	148	151	154	157	160	163
49	Equipment Replacements		-	-	56	57	58	59	60	61	63	64
50												
51	Total Incremental Operating Costs (Savings)	0	0	(516)	(2,369)	(2,490)	(2,616)	(2,738)	(2,875)	(3,018)	(3,166)	(3,318)
52												
53												
54												
55												
56	**Depreciation Expense**											
57	Opening Cash Outlay											
58	Additions in Year											
59	Cumulative Total											
60	Depreciation Rate - composite average											
61	Depreciation Expense											
62												
63	**Net Book Value**											
64	Gross Property	0	17,170	37,507	37,586	37,647	37,709	37,933	37,994	38,054	38,112	39,192
65	Accumulated Depreciation	0	0	(1,276)	(3,977)	(6,684)	(9,395)	(12,110)	(14,832)	(17,559)	(20,290)	(23,024)
66	Net Book Value	0	17,170	36,231	33,609	30,963	28,315	25,823	23,162	20,495	17,823	16,168
67												
68												
69	**Depreciation Expense - Meters**											
70	Opening Cash Outlay	0	0	13,668	31,909	31,988	32,049	32,111	32,173	32,234	32,294	32,353
71	Additions in Year	0	13,668	18,241	79	61	62	62	61	60	59	57
72	Cumulative Total	0	13,668	31,909	31,988	32,049	32,111	32,173	32,234	32,294	32,353	32,409
73	Depreciation Rate - composite average	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
74	Depreciation Expense	0	0	911	2,127	2,133	2,137	2,141	2,145	2,149	2,153	2,157
75												
76	**Net Book Value - Meters**											
77	Gross Property	0	13,668	31,909	31,988	32,049	32,111	32,173	32,234	32,294	32,353	32,409
78	Accumulated Depreciation	0	0	(911)	(3,038)	(5,171)	(7,308)	(9,448)	(11,593)	(13,742)	(15,895)	(18,052)
79	Net Book Value	0	13,668	30,998	28,949	26,878	24,804	22,725	20,641	18,552	16,457	14,357
80												
81												

55	54	52	50	(201)	47	46	34	34	(216)	34	35	35	35	(215)
37,563	37,616	37,669	37,719	37,518	37,565	37,611	37,645	37,679	37,463	37,497	37,532	37,566	37,601	37,387
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(3,588)	(3,738)	(3,907)	(4,082)	(4,263)	(4,450)	(4,644)	(4,822)	(5,021)	(5,229)	(5,446)	(5,672)	(5,907)	(6,138)	(6,395)
(366)	(376)	(386)	(396)	(406)	(417)	(427)	(437)	(447)	(458)	(469)	(480)	(492)	(504)	(516)
(412)	(425)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(43)	(44)	(45)	(47)	(48)
374	386	397	409	421	434	447	460	474	489	503	518	534	550	566
283	289	295	300	306	313	319	325	332	338	345	352	359	366	374
166	170	173	176	180	184	187	191	195	199	203	207	211	215	219
65	67	68	69	71	72	73	75	76	78	80	81	83	84	86
(3,477)	(3,628)	(3,394)	(3,557)	(3,726)	(3,901)	(4,083)	(4,246)	(4,431)	(4,625)	(4,827)	(5,038)	(5,258)	(5,473)	(5,714)
40,470	40,524	40,576	40,626	40,868	41,112	50,095	59,243	69,797	80,561	90,486	90,520	90,555	90,590	90,625
(25,865)	(28,850)	(31,838)	(34,722)	(36,896)	(39,113)	(40,839)	(41,516)	(42,803)	(44,834)	(47,585)	(50,988)	(54,393)	(57,801)	(61,211)
14,605	11,674	8,738	5,905	3,972	2,000	9,255	17,727	26,994	35,728	42,900	39,532	36,162	32,789	29,414
32,409	32,465	32,518	32,570	32,621	32,670	32,717	41,699	50,847	60,178	69,695	79,402	79,437	79,472	79,507
55	54	52	50	49	47	8,982	9,148	9,331	9,517	9,707	35	35	35	35
32,465	32,518	32,570	32,621	32,670	32,717	41,699	50,847	60,178	69,695	79,402	79,437	79,472	79,507	79,542
6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
2,161	2,164	2,168	2,171	2,175	2,178	1,648	599	1,209	1,831	2,465	3,112	3,115	3,117	3,119
32,465	32,518	32,570	32,621	32,670	32,717	41,699	50,847	60,178	69,695	79,402	79,437	79,472	79,507	79,542
(20,213)	(22,377)	(24,545)	(26,716)	(28,891)	(31,069)	(32,717)	(33,316)	(34,525)	(36,355)	(38,821)	(41,933)	(45,048)	(48,165)	(51,284)
12,252	10,141	8,026	5,905	3,779	1,648	8,982	17,532	25,654	33,340	40,582	37,504	34,424	31,342	28,258

82	**Depreciation Expense - Computer Hardware**											
83	Opening Cash Outlay	0	0	143	143	143	143	143	305	305	305	305
84	Additions in Year	0	143	0	0	0	0	162	0	0	0	0
85	Cumulative Total	0	143	143	143	143	143	305	305	305	305	305
86	Depreciation Rate - composite average	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
87	Depreciation Expense	0	0	29	29	29	29	29	32	32	32	32
88												
89	**Net Book Value - Computer Hardware**											
90	Gross Property	0	143	143	143	143	143	305	305	305	305	305
91	Accumulated Depreciation	0	0	(29)	(57)	(86)	(115)	(143)	(176)	(208)	(240)	(273)
92	Net Book Value	0	143	115	86	57	29	162	129	97	65	32
93												
94												
95	**Depreciation Expense - Computer Software**											
96	Opening Cash Outlay	0	0	3,358	5,455	5,455	5,455	5,455	5,455	5,455	5,455	5,455
97	Additions in Year	0	3,358	2,097	0	0	0	0	0	0	0	1,023
98	Cumulative Total	0	3,358	5,455	5,455	5,455	5,455	5,455	5,455	5,455	5,455	6,478
99	Depreciation Rate - composite average	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
100	Depreciation Expense	0	0	336	545	545	545	545	545	545	545	545
101												
102	**Net Book Value - Computer Software**											
103	Gross Property	0	3,358	5,455	5,455	5,455	5,455	5,455	5,455	5,455	5,455	6,478
104	Accumulated Depreciation	0	0	(336)	(881)	(1,427)	(1,972)	(2,518)	(3,063)	(3,609)	(4,154)	(4,700)
105	Net Book Value	0	3,358	5,119	4,574	4,028	3,483	2,937	2,392	1,846	1,301	1,779
106												
107	**Carrying Costs on Average NBV**											
108	Return on Equity	0	310	963	1,260	1,165	1,069	977	884	788	691	613
109	Interest Expense	0	331	1,030	1,347	1,246	1,143	1,044	945	842	739	656
110	AFUDC	0	0	0	0	0	0	0	0	0	0	0
111	**Total Carrying Costs**	0	641	1,993	2,607	2,410	2,213	2,021	1,829	1,630	1,430	1,269
112												
113												
114	**Income Tax Expense**											
115	Combined Income Tax Rate	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
116												
117	**Income Tax on Equity Return**											
118	Return on Equity	0	310	963	1,260	1,165	1,069	977	884	788	691	613
119	Gross up for revenue (Return / (1- tax rate)	0	449	1,376	1,762	1,596	1,465	1,338	1,211	1,079	947	840
120	Income tax on Equity Return	0	139	413	502	431	396	361	327	291	256	227
121												
122	**Income Tax on Timing Differences**											
123	Depreciation Expense	0	0	1,276	2,701	2,707	2,711	2,715	2,723	2,727	2,731	2,735
124	Less: Capital Cost Allowance	0	1,400	4,231	5,206	4,368	3,645	3,040	2,555	2,148	1,807	1,501
125	Total Timing Differences	0	(1,400)	(2,955)	(2,505)	(1,662)	(935)	(326)	168	579	924	1,233
126	Gross up for tax (Total Timing Differences/(1-tax rate))	0	(2,030)	(4,222)	(3,503)	(2,276)	(1,280)	(446)	230	793	1,265	1,690
127	Income tax on Timing Differences	0	(629)	(1,267)	(998)	(615)	(346)	(120)	62	214	342	456

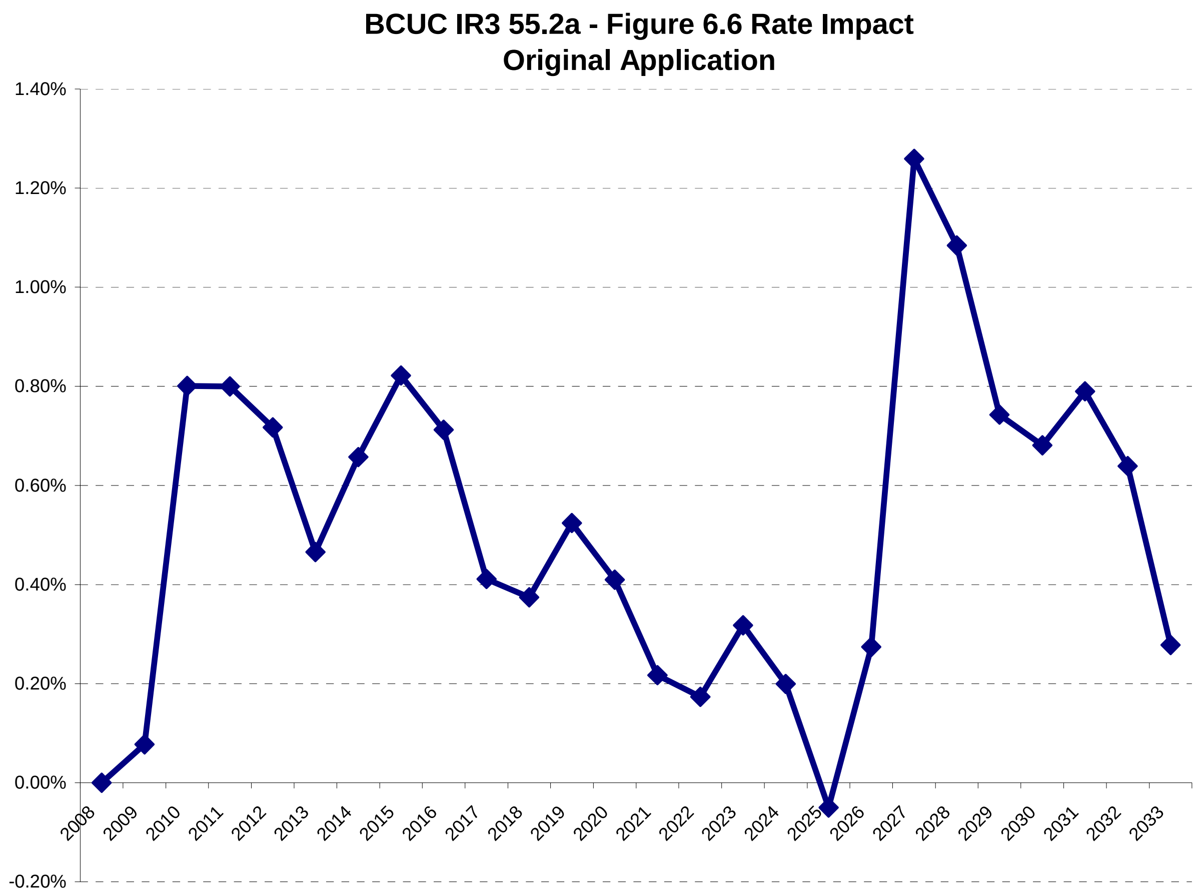
305	483	483	483	483	677	874	874	874	874	874	1,091	1,091	1,091	1,091
178	0	0	0	193	197	0	0	0	0	217	0	0	0	0
483	483	483	483	677	874	874	874	874	874	1,091	1,091	1,091	1,091	1,091
20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
32	68	68	42	0	39	78	78	78	78	39	43	43	43	43
483	483	483	483	676	873	873	873	873	873	1,091	1,091	1,091	1,091	1,091
(305)	(373)	(441)	(483)	(483)	(522)	(600)	(678)	(756)	(834)	(873)	(917)	(960)	(1,004)	(1,047)
178	110	42	0	193	351	273	195	117	39	217	174	130	87	43
6,478	7,522	7,522	7,522	7,522	7,522	7,522	7,522	7,522	8,745	9,992	9,992	9,992	9,992	9,992
1,044	0	0	0	0	0	0	0	1,223	1,247	0	0	0	0	0
7,522	7,522	7,522	7,522	7,522	7,522	7,522	7,522	8,745	9,992	9,992	9,992	9,992	9,992	9,992
10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
648	752	752	670	0	0	0	0	0	122	247	247	247	247	247
7,522	7,522	7,522	7,522	7,522	7,522	7,522	7,522	8,745	9,992	9,992	9,992	9,992	9,992	9,992
(5,347)	(6,100)	(6,852)	(7,522)	(7,522)	(7,522)	(7,522)	(7,522)	(7,522)	(7,644)	(7,891)	(8,138)	(8,385)	(8,632)	(8,880)
2,175	1,422	670	0	0	0	0	0	1,223	2,348	2,101	1,854	1,607	1,360	1,113
555	474	368	264	178	108	203	487	807	1,132	1,418	1,487	1,366	1,244	1,122
594	507	394	282	191	115	217	520	863	1,210	1,517	1,590	1,460	1,330	1,200
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1,149	981	762	547	369	223	420	1,007	1,669	2,341	2,935	3,077	2,826	2,574	2,322
27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
555	474	368	264	178	108	203	487	807	1,132	1,418	1,487	1,366	1,244	1,122
760	649	504	362	244	148	278	667	1,105	1,550	1,943	2,037	1,871	1,704	1,537
205	175	136	98	66	40	75	180	298	419	525	550	505	460	415
2,841	2,985	2,988	2,884	2,175	2,217	1,726	677	1,287	2,031	2,752	3,403	3,405	3,408	3,410
1,245	1,051	888	752	617	504	429	366	311	246	191	165	144	126	91
1,596	1,934	2,100	2,132	1,558	1,713	1,297	311	975	1,785	2,561	3,238	3,261	3,281	3,319
2,186	2,649	2,877	2,921	2,134	2,347	1,777	426	1,336	2,446	3,508	4,435	4,467	4,495	4,546
590	715	777	789	576	634	480	115	361	660	947	1,197	1,206	1,214	1,228

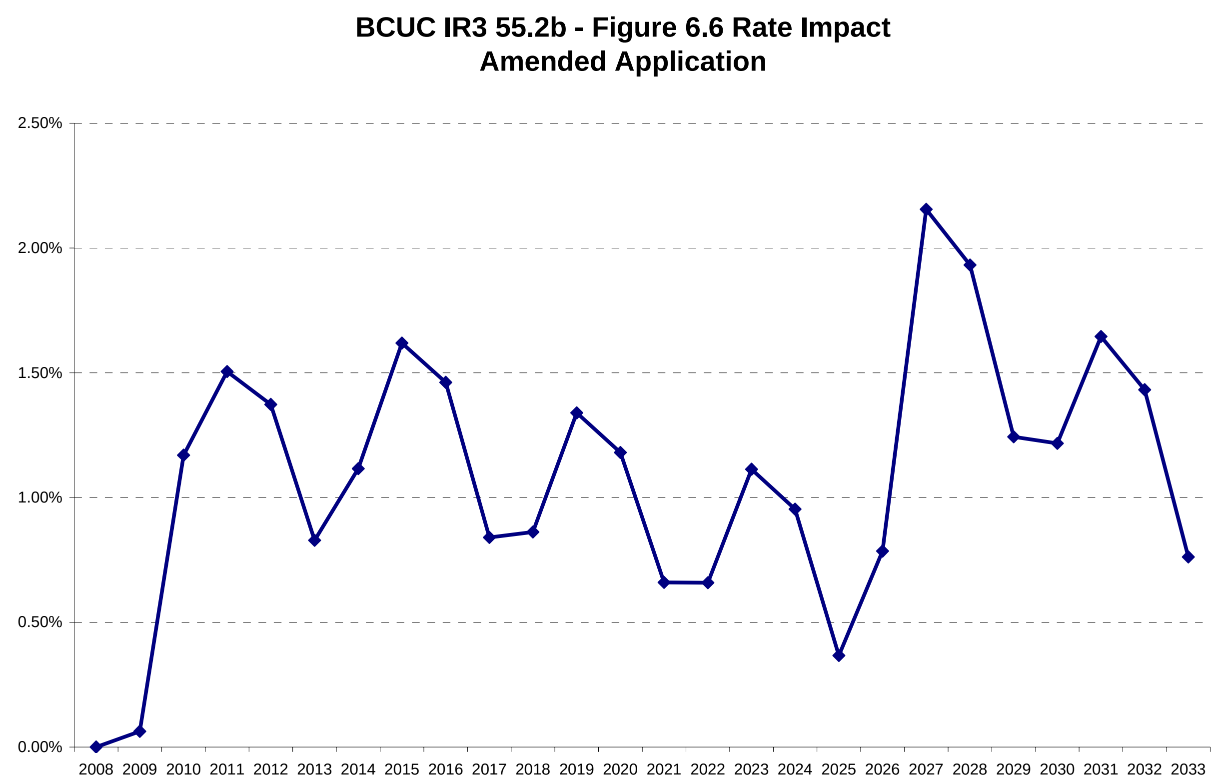
128												
129	**Total Income Tax**	0	(490)	(854)	(496)	(184)	50	241	389	505	597	683
130												
131												
132	**Capital Cost Allowance**											
133	Opening Balance - UCC	0	0	15,769	31,876	26,748	22,441	18,608	15,629	13,136	11,048	9,300
134	Additions	0	17,170	20,337	79	61	(188)	62	61	60	59	(193)
135	Subtotal UCC	0	17,170	36,107	31,955	26,810	22,253	18,670	15,691	13,196	11,107	9,106
136	Capital Cost Allowance Rate	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%
137	CCA on Opening Balance	0	0	2,572	5,200	4,363	3,661	3,035	2,550	2,143	1,802	1,517
138	CCA on Capital Expenditures (1/2 yr rule)	0	1,400	1,659	6	5	(15)	5	5	5	5	(16)
139	Total CCA	0	1,400	4,231	5,206	4,368	3,645	3,040	2,555	2,148	1,807	1,501
140	Ending Balance UCC	0	15,769	31,876	26,748	22,441	18,608	15,629	13,136	11,048	9,300	7,605

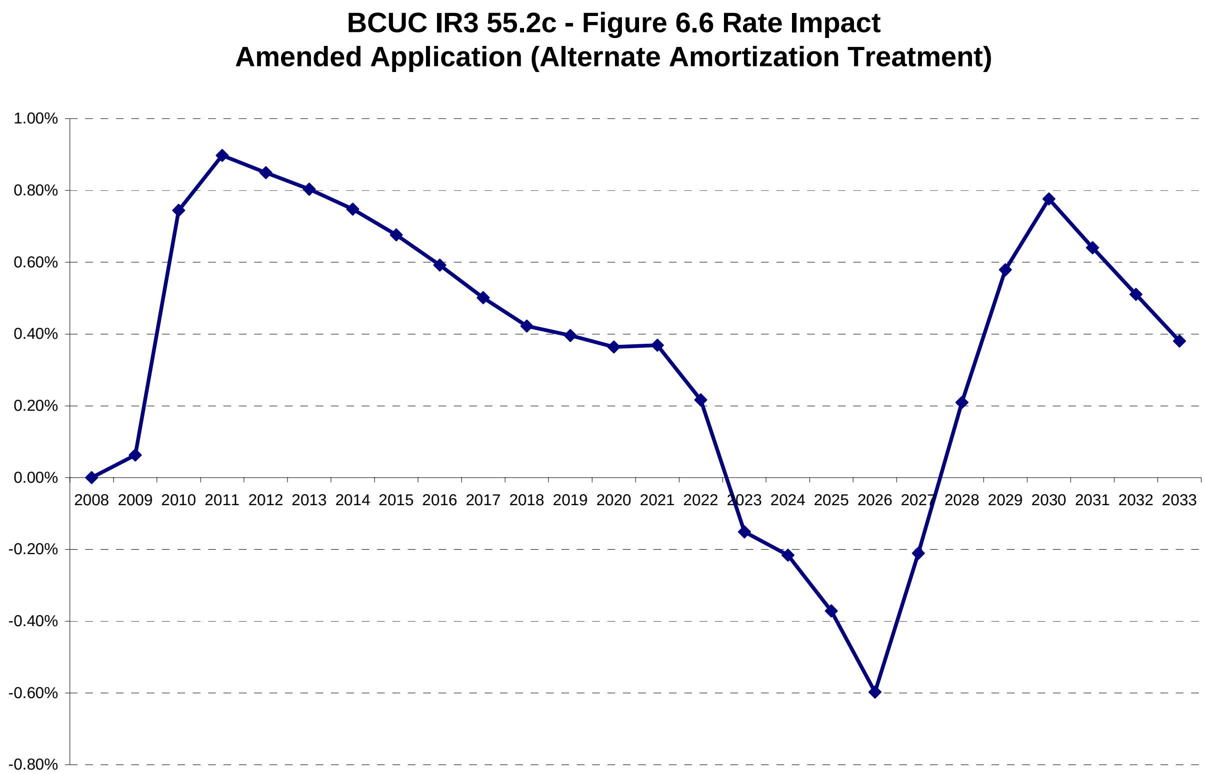
796	891	913	886	642	673	555	295	659	1,079	1,472	1,747	1,711	1,674	1,643
7,605	6,415	5,418	4,582	3,881	3,063	2,607	2,224	1,892	1,614	1,153	996	865	756	665
55	54	52	50	(201)	47	46	34	34	(216)	34	35	35	35	(215)
7,660	6,469	5,470	4,633	3,680	3,111	2,653	2,258	1,926	1,399	1,187	1,031	900	791	450
16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%
1,241	1,047	884	747	633	500	425	363	309	263	188	163	141	123	108
5	4	4	4	(16)	4	4	3	3	(18)	3	3	3	3	(18)
1,245	1,051	888	752	617	504	429	366	311	246	191	165	144	126	91
6,415	5,418	4,582	3,881	3,063	2,607	2,224	1,892	1,614	1,153	996	865	756	665	359

Q55.2 Please provide updated Amended Figure 6.6 Rate Impact for the above scenarios.

A55.2 The requested information is provided below.




BCUC IR3 55.2b - Figure 6.6 Rate Impact
Amended Application
2.50%
2.00%
1.50%
1.00%
0.50%
0.00%
2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033


BCUC IR3 55.2c - Figure 6.6 Rate Impact
Amended Application (Alternate Amortization Treatment)
1.00%
0.80%
0.60%
0.40%
0.20%
0.00%
-0.20%
-0.40%
-0.60%
-0.80%
2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033

56.0 Reference: Demand Response

Exhibit B-6, 4. Revisions to Functional Requirements, pp.10-11

Amended Table 7.1: AMI Functions and Features

Q56.1 Would FortisBC please provide the planned percentage use of the features, and indicate whether they are optional or required when compared to Reported [9]Uses of AMI by Other Utilities?

A56.1 Figure III-9 in the FERC study quoted in this question relates to the percentage of utilities using AMI for each of the following reasons. Table 56.1 below compares FortisBC's requirements with the FERC study as they relate to uses of the AMI system functionalities.

Table A56.1: FortisBC AMI Functionality Utilization

Category	**FERC % of Utilities Using AMI for this category**	**FortisBC Using AMI for this category?**	**Table 7.1 Benefits Supporting this Category**
Customer Service	~70%	Yes	Hourly readings Virtual disconnect reporting Restoration verification Interface to customer web access Outage management functions Interface to CIS Billing System
Tamper	~42%	Yes	Hourly readings Complex reporting
Load Forecasting	~42%	Yes	Hourly readings
Power Quality Monitoring	~35%	Optional	Voltage Reading
Outage Management	~33%	Yes	Outage management functions

[9] FERC Staff Report on Demand Response and Advanced Metering, by David Kathan, FERC October 10, 2006 Slide 14.

Price responsive DR	~26%	Future use	Hourly readings HAN supporting in-home display and load control
Remotely Changing meter parameters	~25%	Yes	Compatibility with Measurement Canada regulations
Asset Management	~23%	Future use	Hourly readings Interface to field mapping system
Premise device / load control	~22%	Future use	HAN supporting in-home display and load control
Reduce Line Losses	~18%	Yes	Hourly readings Interface to field mapping system Interface to CIS Billing System
Remote disconnect / reconnect	~18%	Future use	Supports remote disconnect / reconnect
Other	~13%	N/A	N/A
Pricing event notification capability	~13%	Future use	Hourly readings HAN supporting in-home display
Gas / Water meter reads	~8%	Future use	
Prepay Metering	~1%	Future use	

Q56.2 Would FortisBC please supply an explanation as to why tamper detection is optional when it is indicated as a high use feature by other utilities?

A56.2 As a point of clarification, although FortisBC has made “tamper detection” functionalities optional for the AMI project, the intention is to use the improved data from the AMI system to identify and resolve possible tampering situations. FortisBC has an active Revenue Protection program that reviews customer usage patterns and receives information from various sources to identify possible tampering situations. AMI will strengthen the data available to be used for this purpose. Please also see the response to BCUC IR No. 3 Q56.1.

Q56.3 Would FortisBC please provide comment on the other features that may also be considered as optional and have high use by other utilities?

A56.3 Power quality monitoring is considered an optional feature by FortisBC although it has a high use by other utilities. Voltage readings were not considered mandatory, since there are no economic benefits associated with them directly.

Although Voltage readings are optional, preference will be given to vendors that can supply them at no additional cost to the project.

57.0 Reference: Residential Customers

Exhibit B-6, Amended Application, p. 4; Exhibit B-6, 2. House Area Network, p. 5

Customer Best Interests & In-house Devices

FortisBC states that "FortisBC believes the enhancements in this amendment are in the best interest of customers, and offer more flexibility and support for the BC Energy Plan at a reasonable cost. FortisBC therefore requests approval of a CPCN for the AMI Project as described in this Amended Application."

Q57.1 Would FortisBC please explain how low-income and other vulnerable customers will benefit from AMI and time of use rates?

A57.1 Low income and other vulnerable customers will benefit from AMI in the same way that other customers will benefit. Some of those benefits are:

- more accurate meter readings;
- the elimination of meter reading estimates on bills;
- reduced need for access to customer properties;
- better information on hourly consumption through the internet;
- actual readings on the day of the move in/move out;
- flexible billing dates; and

- line loss reductions.

If implemented in the future, these customers may also benefit from time-of-use rates to the extent that they are able to shift consumption from on-peak times to off-peak times and therefore reduce their overall electrical consumption. This may contribute to reduced power purchase costs and potentially delay capital investments in generation and/or transmission infrastructure. Although FortisBC is not capable of identifying low income or other vulnerable customers, the Company is investigating a number of ways in which these customers may be assisted which are described in the response to BCUC IR No. 3 Q57.6.

Q57.2 Would FortisBC please explain the extent to which those who cannot shift load will do better or worse than the status quo?

A57.2 This answer depends of the specific design of the rate in question. Time-based rates can be designed that penalize, reward or have no impact on those customers who do not change their consumption behaviour.

Q57.3 If 100% of the demand response benefits are available to those who respond by lowering demand, then would all customers be paying for AMI metering that only some customers will be able to use to their benefit? Would FortisBC please provide comment?

A57.3 The Amended Application provides benefits to all customers as described in the response to BCUC IR No. 3 Q57.1, and those benefits pay for the majority of the AMI Project costs. Future benefits derived from demand response management or time-based rates would be primarily realized by the customers who contribute to the savings, as described in response to BCUC IR No. 3 Q38.5.2.

Q57.4 Please provide FortisBC's estimate of consumers' price elasticity of demand. Please indicate the basis for the values provided.

A57.4 FortisBC believes the consumers' price elasticity of demand to be in the ranges shown below based on elasticity studies performed by EES Consulting Inc., and their review of published data.

Customer Class	Elasticity of Demand
Residential	-0.1 to -0.3
Commercial	-0.1 to -0.3
Industrial	-0.1 to -0.8

Q57.5 Given the relative inelasticity of energy demand (including, for example, gasoline) among most Canadian consumers, does FortisBC have an estimate of the extent to which on-peak and/or critical peak prices would have to rise to obtain a meaningful customer response?

A57.5 Price response, in studies such as the Ontario Smart Price Pilot (SPP), has been shown to have some effect on consumption when peak prices are double or triple off-peak rates. When time-based pricing is combined with improved information through means such as in-home displays, the effects are greater.

Q57.6 Is it possible for FortisBC to identify customers who are both low-income and high-usage, to prevent them from experiencing major bill increases as a result of an AMI investment and subsequent implementation of time-varying prices?

A57.6 FortisBC cannot identify low income customers, however FortisBC is working with the Provincial Government through the BC Partnership for Energy Conservation and Efficiency on a provincial standard for identifying low-income customers. The Company is concerned about the impact of time-based rates on low-income customers that may have limited control over the amount of electricity they use. FortisBC is investigating a number of ways in which these customers may be assisted, including:

- Designing PowerSense programs that reach low-income customers and help their reduce consumption, such as Compact Fluorescent Lighting giveaways;
- Working with BC utilities looking at ways of assisting low-income customers; and
- Exploring relationships with government agencies and low-income housing owners to improve building envelopes and reduce consumption.

In addition, FortisBC will specifically consider the issue of low-income customer impact in any time-based rate design application.

Q57.7 Is it possible for FortisBC to assist customers who are both low-income and high-usage, to prevent them from experiencing major bill increases as a result of an AMI investment and subsequent implementation of time-varying prices?

A57.7 Please see the response to BCUC IR No. 3 Q57.6.

Q57.8 What funds has FortisBC allowed for AMI customer outreach and education in this proposal or in the future?

A57.8 During the initial installation of AMI, customer communication will be limited to the information about the new meters and the installation process. FortisBC expects to contact customers through a variety of means advising them of the installation dates in their area and outlining any impacts to them. Customer impacts will involve short outages while the meter is exchanged as well as possible impacts to meter cabinets or other structures currently built around the meter. FortisBC has allowed a $250,000 budget for this customer communication.

A more extensive customer communication and outreach plan related to DSM or other AMI related initiatives will be part of the implementation of those features in the future.

Q57.9 Does FortisBC have a communications plan to ensure that customers, municipalities and the general public are aware of the AMI and HAN changes that will impact them directly?

A57.9 Please see the response to BCUC IR No. 3 Q57.8.

58.0 Reference: Residential Customers
Exhibit B-6, 2. House Area Network, p. 5
In-house Devices

Q58.1 What are the customer computer requirements and training required for the use of HAN?

A58.1 There are no computer or training requirements for the installation of the HAN communications infrastructure planned for the AMI installation.

Most basic in home display units do not require the customer to have a computer since the communication will be coming from the AMI system, not through the internet.

Home displays that could be added to the HAN at a future point range from simple displays of consumption to more complex, programmable thermostat type of displays. In most cases, the devices are simple enough that a homeowner could learn to use it through simple instructions included with the device. If FortisBC is providing those displays to customers, there would also be support available through the Contact Center.

Q58.2 Statistics Canada indicates that in 2005 BC internet use by individuals was 34.1% (telephone users) and 61% (cable user); that only 22.5% of those over 65 had internet access from home; that only 26.5% of those with less than high school education have internet access from home.

Q58.2.1 Would FortisBC please explain how computer gateway devices and HAN will assist these different groups?

A58.2.1 Please see the response to BCUC IR No. 3 Q58.1

Q58.3 Will FortisBC be offering any HAN devices to its customers as part of this program?

A58.3 No, FortisBC will not be offering any HAN devices to customers as part of the initial installation of AMI. The response to BCUC IR No. 3 Q42.1 describes the criteria by which FortisBC would supply in-home displays.

Q58.4 What is the estimated cost per household of Direct Energy's pilot project Direct Energy Conservation Program using a Smart Home Energy Conservation Kit for Milton Hydro?

A58.4 FortisBC was not able to find an estimated of the cost per household for Milton Hydro's Energy Conservation Kit. However, publicly available documents state that the kit has an estimated value of $1,000 per kit.

59.0 Reference: HAN

Exhibit B-6, p. 5

FortisBC states: "The HAN that supports in-home display would also support future smart grid applications. This would enable FortisBC and its customers to control certain household appliances and subsequently reduce residential loads during critical peak periods, if such capability was implemented in future."

Q59.1 Please confirm the incremental capital costs associated with the added HAN functionality are $2 million.

A59.1 The addition of both hourly readings and the HAN communications functionality is confirmed to be $2 million dollars.

Q59.2 Please indicate what portion of the additional operating expenses ($727 thousand per year vs. $524 thousand per year) summarized in Amended Table 4.1.1 is associated with providing HAN functionality.

A59.2 There are no incremental operating expenses currently expected with providing the HAN functionality. This is because the functionality will be limited to providing the communications infrastructure only to allow the future add-on of in-home displays or load control devices.

Q59.3 What additional costs would potentially be incurred by FortisBC and/or its customers to utilize the HAN functionality? If possible, provide costs associated with specific HAN functions (e.g., in-home display devices, load control devices, etc.). Please separate costs that would be incurred by FortisBC to enable / utilize these HAN functions versus costs that would be incurred by customers themselves to take advantage of these features.

A59.3 Please see the response to BCUC IR No. 3 Q42.1.

Q59.4 Please provide a simple scenario analysis for a hypothetical residential customer (based on a typical residential level of consumption and load profile) that illustrates the incremental costs associated with different levels of HAN functionality and the incremental benefits that customer may see as a result of those functions in terms of reduced bills. Please also include an analysis of the avoided costs to the utility from changes in consumption patterns as a result of the features enabled by a HAN.

A59.4 The assumptions made in the answer to this question are:

- monthly consumption of 2,000 kWh;
- a residential rate of $0.05 per kWh off-peak and $0.15 on-peak (based on FortisBC historical rate);
- electrical savings during on-peak hours at various levels of HAN functionality as described in Horizon IR No. 3 Q3.5;
- higher electric use during off-peak hours at 50 percent of levels as described in Horizon IR No. 3 Q3.5 (since not all of the energy saved during on-peak hours will be consumed in-off peak hours, for example savings due to turning off lights and turning down the heat);
- on-peak hours at 8 hours per day; and
- baseline monthly bill of $233 based on two-thirds of consumption occurring during on-peak hours

Incremental monthly savings are calculated as:

2000 kWh * (16 hours / 24 hours/day * 0.05 $/kWh * off-peak increase - 8 hours / 24 hours/day * 0.15 $/kWh * on-peak savings).

Table A59.4a: Savings per Residential Customer

HAN Functionality	Incremental monthly savings ($)	Savings (%)
Innovative rates only	1.33 – 3.33	0.6 - 1.4
Innovative rates + in-home display	3.33	1.4
Load control	1.33 – 23.33	0.6 – 10.0

Assumptions for avoided power purchase costs are as above, and including the following:

- residential load factor of 53 percent;
- residential customers contribute to the peak 4 months (2 months for the summer peak and two months for the winter peak) of the year;
- capacity costs as outlined in BCUC IR No. 3 Q38.8 ($200,600 per MW per year / 1000 kW/MW / 12 months/year = $16.72 per kW per month); and
- energy costs of $0.03 / kWh

Therefore, avoided power purchase costs are calculated as:

Energy: 2000 kWh * 50% * on-peak savings * $0.03 / kWh

Capacity: 2000 kWh / 731 h/month / 0.53 * 16.72 $/kW * on-peak savings * 4/12 months

Therefore, avoided power purchase costs would be as follows:

Table A59.4b: Avoided Power Purchase Costs

HAN Functionality	Incremental monthly savings ($)
Innovative rates only	1.18 – 2.94
Innovative rates + in-home display	2.94
Load control	1.18 – 14.71

Q59.5 Please provide any case studies FortisBC is aware of for other utilities illustrating the costs and benefits of HAN functionality.

A59.5 FortisBC is not aware of any case studies illustrating the costs and benefits of HAN functionality. However, the Company has provided the information attached as BCUC Appendix 59.5 which describes a discussion of the benefits of HAN functionality.

Q59.6 Please summarize which utilities / jurisdictions have included HAN functionality in their AMI specifications and which are actively pursuing pursing that functionality. Does the AMI being implemented by FortisAlberta include HAN functionality and are there currently any plans to leverage that functionality in Alberta?

A59.6 FortisBC is unable to find information in this level of detail for utilities other than those in Ontario and FortisAlberta since most AMI specification and RFP documents are confidential.

FortisAlberta's AMI technology is also capable of communicating through a HAN, but at this time there are no plans to leverage that functionality.

60.0 Reference: TOU Rates

Exhibit B-6, p. 7

FortisBC states: "Although standard time-of-use rates can be calculated using On Meter, the number of "time buckets" is limited by the frequency of data transmission and the memory of the meter…CPP adds another layer of complexity to billing that is better supported by hourly readings."

Q60.1 How many "time buckets" are typically used in TOU rates for residential and commercial customers?

A60.1 Currently, approximately three to six time buckets are used in typical TOU rates for residential and commercial customers. This has been up until recently, limited, as AMI and hourly technology has not been widely deployed. More complicated TOU rates that use more than six time buckets may provide better results and be more commonly used once AMI technologies are in place.

Q60.2 Please discuss what may constitute a critical peak period in the context of FortisBC's system as compared to other jurisdictions – e.g., a largely hydro-based system versus a thermal system. Please discuss the specific potential applicability (benefits) of CPP in the context of FortisBC's load profile and resource mix.

A60.2 As discussed in the response to BCUC IR No. 3 Q38.6, the Company's marginal cost of capacity is between $165,000 and $245,000 per MW assuming company owned generation to meet loads. FortisBC summer peaks have been increasing faster than winter peaks over the past few years, with resource acquisition through the twenty year planning period driven by peak requirements. Therefore, any critical peaking program that seeks to reduce Company peak capacity requirements must concentrate on the winter and summer peak hours of 4 PM to 7 PM weekdays. Depending on the extent of reductions required, other hours may have to be included as well. In addition, to be a truly critical peak period, the program only needs to be in effect on the coldest and warmest of days. Given an assumed shift to company owned resources to meet load, reducing the planned load in this manner will directly impact the required company generation to meet that load.

However, load shedding on demand (such as a hot water tank program) can have large benefits outside of critical peak periods since they can play a significant role in assisting the Company in dealing with the immediate operational issues of higher than expected load or generation unit outages.

All utilities, regardless of generation source, share similar concerns with meeting peak loads with generation that is only required a few hours a year. However, due to the nature of FortisBC's generation coordination agreement with BC Hydro (The Canal Plant Agreement) and our Power Purchase Agreement with BC Hydro, the Company does not share the common utility concerns with items such as ramp rates at this time. FortisBC is unable to provide a detailed analysis of issues other utilities may have.

Q60.3 Approximately what portion of current TOU tariffs in North America are supported by On-Meter versus Off Meter consumption tracking?

A60.3 The majority of North American TOU tariffs currently support off meter consumption tracking since AMI has not been deployed in all regions. Ontario is the largest region in Canada that is expecting to use on-meter consumption tracking once AMI is deployed and TOU rates are implemented.

Q60.4 What are the costs and issues associated with remote programming of meters with On-Meter consumption tracking to support TOU tariffs?

A60.4 Measurement Canada currently allows remote configuration under the meter seal. Therefore, meters can be re-programmed without breaking the meter seal. Some communication systems allow this to be done remotely. In those cases, the cost would be minimal. Some communication systems require that a technician be on site with the meter even though the meter itself does not need to be replaced. In those cases, the cost could be significant, depending on the scale of the TOU tariff used.

61.0 Reference: Remote Disconnect/Reconnect
Exhibit B-6, BCOAPO et al IR No. 1 Amended Application, p. 58
Required in the Amended Application, Exhibit B-6, p. 11

Q61.1 Under what circumstances would FortisBC initiate a remote disconnect of service?

A61.1 If a remote disconnect/reconnect were installed on a meter, FortisBC would initiate a remote disconnect of service for any reason that a physical disconnection is completed now. This could include both customer (customer moves, salvages etc.) and Company initiated disconnections (non-payment, safety, no new customer etc.).

Q61.2 How does FortisBC propose to notify the customer when using this function both for maintenance and billing issues?

A61.2 Customers would be notified of a disconnection the same way they are today, that is, by bill message, letter, or phone for a physical site disconnection with the exception of a door tag. In the event that FortisBC decides to avail itself of the remote disconnect/reconnect option in the future, policies will be put in place to ensure the customer receives adequate notification and that the meter can also be safely reconnected remotely.

Q61.3 In the instance Remote Disconnect/Reconnect over bill payment issues, what procedure will FortisBC follow before initiating a remote disconnect of service?

A61.3 In the event of a non-pay disconnection, customers would be notified of a disconnection the same way they are today (via bill messages, letters and phone calls).

Q61.3.1 In the instance Remote Disconnect/Reconnect over bill payment issues, would FortisBC not consider initiating a remote disconnect of service?

A61.3.1 Please refer to the response to BCUC IR No. 3 Q61.1.

62.0 Reference: Project Costs
Exhibit B-6, 6. Revisions to Project Costs, p. 12
Amended Table 6.3: Summary of Capital Costs

Q62.1 Would FortisBC please explain why the Project Management cost remained unchanged at $2,701,000?

A62.1 The addition of hourly readings and HAN communications modules are not expected to require any additional project management support than what was already established for the AMI project. The VEE equipped MDMR is expected to be provided by an outside vendor and the incremental cost of $3.5 million includes the additional software configuration, testing and project management required by that vendor to deliver on the requirements.

63.0 Reference: Public Consultation
Exhibit B-6, Covering Letter

FortisBC states that "During the Regulatory process associated with the Original Application, FortisBC continued to engage in public consultation with stakeholders including discussions with the Ministry of Energy, Mines and Petroleum Resources with regard to FortisBC's AMI Project."

Q63.1 Did FortisBC hold any public consultation sessions with its ratepayers during the regulatory process? Please explain.

A63.1 Please see the response to BCUC IR No. 1 Q37.1.

64.0 Reference: DCF Analysis

Exhibit B-6, p. 26-39, Amended BCUC 1.12.0 AND p. 69- 70, Amended BCUC 2.12.2

Q64.1 Please provide two additional DCF analyses assuming the economic life of the meters is 15 years (i.e., replacement required after 15 years), the economic life of the computer hardware is five years, and the economic life of the computer software is three years and using the base case assumptions in a) the original application and b) the amended application. Include the replacement costs for each component and include a terminal value at the end of 25 years for the remaining economic value of each component (e.g., there would be two meter replacements during the 25 year analysis period and five years of economic life remaining on the meters at the end of 25 years).

A64.1 Please see the DCF analyses titled BCUC IR3 64.1a and 64.1b below.

Discounted Cash Flow Analysis BCUC IR3 64.1a
Option "AMI"
Original Application

Line No.		NPV @ 8.00%	0 2008	1 2009	2 2010	3 2011	4 2012	5 2013	6 2014	7 2015	8 2016	9 2017	10 2018
	Summary												
	Discounted Cash Flow												
1	**Capital Costs**												
2	Meter Costs												
3	New	**1,321**	89	200	178	145	112	114	113	112	109	107	104
4	Replacement	**20,862**	0	6,863	11,381	0	0	0	0	0	0	0	0
4		**22,183**	**89**	**7,063**	**11,558**	**145**	**112**	**114**	**113**	**112**	**109**	**107**	**104**
5	Meter Reading Equipment	**0**	0	0	0	0	0	0	0	0	0	0	0
6	Network Infrastrucuture	**15,065**	0	3,176	3,085	0	0	0	3,176	3,176	0	0	0
7	IT infrastructure and upgrades	**4,981**	0	1,242	144	0	0	0	1,242	1,242	0	0	0
8	Project Management	**2,991**	515	989	1,031	0	0	0	0	0	0	0	0
9		**45,219**	604	12,471	15,818	145	112	114	4,532	4,531	109	107	104
10	**Operating Costs**												
11	Meter Reading												
12	Labour	**4,144**	1,565	1,622	1,257	0	0	0	0	0	0	0	0
13	Non-Labour	**1,356**	506	532	418	0	0	0	0	0	0	0	0
14		**5,500**	2,070	2,154	1,675	0	0	0	0	0	0	0	0
15	T&D operating cost	**1,787**	276	283	289	0	0	0	0	0	0	0	0
16	Customer service	**7,250**	263	271	354	699	702	705	708	711	714	717	720
17	Income taxes	**5,374**	0	(344)	(433)	(145)	40	36	353	649	720	603	691
18		**19,911**	2,609	2,364	1,885	554	743	741	1,061	1,360	1,434	1,320	1,412
19	**GHG Reduction (217.6 tonnes)**	**0**	0	0	0	0	0	0	0	0	0	0	0
20	**Net Cash Flow**	**65,130**	**3,213**	**14,835**	**17,704**	**699**	**855**	**855**	**5,592**	**5,891**	**1,544**	**1,427**	**1,515**
21	**Discounted Cash Flow**	**65,130**	**3,213**	**13,736**	**15,178**	**555**	**628**	**582**	**3,524**	**3,437**	**834**	**714**	**702**

11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
101	98	96	92	90	86	84	62	62	62	63	63	64	64	64
0	0	0	0	0	0	6,959	11,466	0	0	0	0	0	0	0
101	**98**	**96**	**92**	**90**	**86**	**7,043**	**11,528**	**62**	**62**	**63**	**63**	**64**	**64**	**64**
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3,176	3,176	0	0	0	3,176	3,176	0	0	0	3,176	3,176	0	0	0
1,242	1,242	0	0	0	1,242	1,242	0	0	0	1,242	1,242	0	0	0
0	0	0	0	0	515	989	1,031	0	0	0	0	0	0	0
4,520	4,516	96	92	90	5,020	12,451	12,559	62	62	4,481	4,482	64	64	64
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	306	309	312	315	318	320	322	324	326	328	331	333	335
723	727	730	733	736	740	743	746	750	753	756	760	763	767	770
949	968	790	836	1,077	1,073	667	953	1,727	1,700	1,452	1,466	1,704	1,661	1,370
1,672	1,695	1,826	1,878	2,125	2,127	1,728	2,019	2,798	2,777	2,534	2,554	2,798	2,760	2,476
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6,192	**6,211**	**1,922**	**1,970**	**2,215**	**7,147**	**14,179**	**14,578**	**2,860**	**2,839**	**7,016**	**7,036**	**2,862**	**2,824**	**2,540**
2,656	**2,467**	**707**	**671**	**698**	**2,086**	**3,832**	**3,648**	**663**	**609**	**1,394**	**1,294**	**487**	**445**	**371**

Discounted Cash Flow Analysis BCUC IR3 64.1b
Option "AMI"
Amended Application

Line No.		NPV @ 8.00%	0 2008	1 2009	2 2010	3 2011	4 2012	5 2013	6 2014	7 2015	8 2016	9 2017	10 2018
	Summary												
	Discounted Cash Flow												
1	**Capital Costs**												
2	Meter Costs												
3	New	**1,321**	89	200	178	145	112	114	113	112	109	107	104
4	Replacement	**30,339**	0	7,413	19,343	0	0	0	0	0	0	0	0
4		**31,660**	**89**	**7,613**	**19,521**	**145**	**112**	**114**	**113**	**112**	**109**	**107**	**104**
5	Meter Reading Equipment	**0**	0	0	0	0	0	0	0	0	0	0	0
6	Network Infrastrucuture	**17,318**	0	3,660	3,602	0	0	0	3,660	3,602	0	0	0
7	IT infrastructure and upgrades	**11,272**	0	2,892	1,794	0	0	0	2,892	1,794	0	0	0
8	Project Management	**2,991**	515	989	1,031	0	0	0	0	0	0	0	0
9		**63,240**	604	15,155	25,948	145	112	114	6,666	5,508	109	107	104
10	**Operating Costs**												
11	Meter Reading												
12	Labour	**4,144**	1,565	1,622	1,257	0	0	0	0	0	0	0	0
13	Non-Labour	**1,356**	506	532	418	0	0	0	0	0	0	0	0
14		**5,500**	2,070	2,154	1,675	0	0	0	0	0	0	0	0
15	T&D operating cost	**1,787**	276	283	289	0	0	0	0	0	0	0	0
16	Customer service	**7,311**	263	271	354	706	709	712	715	718	721	724	727
17	Income taxes	**9,215**	0	(490)	(524)	(9)	251	86	520	1,142	1,232	876	1,027
18		**23,813**	2,609	2,218	1,794	697	960	798	1,235	1,860	1,953	1,600	1,755
19	**GHG Reduction (217.6 tonnes)**	**0**	0	0	0	0	0	0	0	0	0	0	0
20	**Net Cash Flow**	**87,053**	**3,213**	**17,373**	**27,742**	**842**	**1,072**	**912**	**7,901**	**7,368**	**2,063**	**1,707**	**1,858**
21	**Discounted Cash Flow**	**87,053**	**3,213**	**16,086**	**23,784**	**668**	**788**	**620**	**4,979**	**4,299**	**1,114**	**854**	**861**

11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
101	98	96	92	90	86	84	62	62	62	63	63	64	64	64
0	0	0	0	0	0	7,509	19,429	0	0	0	0	0	0	0
101	**98**	**96**	**92**	**90**	**86**	**7,593**	**19,490**	**62**	**62**	**63**	**63**	**64**	**64**	**64**
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3,660	3,602	0	0	0	3,660	3,602	0	0	0	3,660	3,602	0	0	0
2,892	1,794	0	0	0	2,892	1,794	0	0	0	2,892	1,794	0	0	0
0	0	0	0	0	515	989	1,031	0	0	0	0	0	0	0
6,654	5,494	96	92	90	7,154	13,979	20,521	62	62	6,615	5,459	64	64	64
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	306	309	312	315	318	320	322	324	326	328	331	333	335
730	734	737	740	743	746	750	753	756	760	763	767	770	774	777
1,601	1,624	1,163	1,247	1,802	1,795	1,210	1,455	2,855	2,797	2,187	2,243	2,851	2,773	2,121
2,332	2,358	2,206	2,297	2,858	2,856	2,278	2,528	3,933	3,881	3,277	3,338	3,952	3,879	3,233
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8,986	**7,852**	**2,302**	**2,389**	**2,947**	**10,010**	**16,257**	**23,050**	**3,995**	**3,943**	**9,892**	**8,797**	**4,016**	**3,943**	**3,297**
3,854	**3,118**	**846**	**813**	**929**	**2,922**	**4,394**	**5,768**	**926**	**846**	**1,965**	**1,618**	**684**	**622**	**481**

65.0 Reference: Nominal and Real Dollar Analysis
Exhibit B-6, pp. 26-39, Amended BCUC 1.12.0 AND pp. 69-70, Amended BCUC 2.12.2

Q65.1 FortisBC provided an updated real dollar analysis (with sensitivities) in Amended BCUC 2.12.2 that includes real escalation. In Amended BCUC 1.12.0, FortisBC provided a nominal dollar analysis (with sensitivities) that includes nominal escalation rates. Mathematically, a real dollar analysis using real dollars (with real escalation) and a real discount rate should yield approximately the same NPV as a nominal dollar analysis (with nominal escalation) and a nominal discount rate. Both analyses will yield an NPV that is in dollars of whatever year is used as the starting point (in this case 2008). Scenario B1 in Amended BCUC 1.12.0, which is a nominal dollar analysis, shows a net cost of the Amended AMI program of $3,837 million at a 10% nominal discount rate and based on the nominal escalation rates shown in the introduction to Set B scenarios. Scenario A1 in Amended BCUC 2.12.2 shows a net cost of the AMI program of $5,852 at an 8% real discount rate (which is approximately equivalent to a 10% nominal discount rate). The real dollar analysis includes real escalation of labour and vehicle costs. Please explain the discrepancies in the nominal and real dollar analyses given the input assumptions are essentially the same except one uses nominal dollars and a nominal discount rate and the other uses real dollars and a real discount rate (both in the context of the original and amended applications). Which set of analyses does FortisBC consider the Commission should rely on?

A65.1 The primary difference between the two analyses is due to the relative weight of each cost component and its expected inflation factor. This is illustrated in Table A65.1 below. Because the individual components may experience inflation at a rate different from general inflation, the real expense associated with each component will differ and result in different discounted amounts. For this reason the Company is of the opinion that the Commission should rely on the analysis in nominal dollars.

Table A65.1: Nominal vs. Real Dollars NPV Analysis

Year		**0**	**1**	**2**	**3**	**4**	
General Inflation			2.0%	2.0%	2.0%	2.0%	
Expense Specific Inflation			5.0%	5.0%	5.0%	5.0%	
Expense Specific Real Inflation			3.0%	3.0%	3.0%	3.0%	
							NPV
Nominal Dollars							
Expense		100.00	105.00	110.25	115.76	121.55	
Discounted at	10.0%	100.00	95.45	91.12	86.97	83.02	**456.57**
Real Dollars							
Expense		100.00	103.00	106.09	109.27	112.55	
Discounted at	8.0%	100.00	93.64	87.68	82.10	76.87	**440.29**

66.0 Reference: Rate Impact Analysis

Exhibit B-6, p. 14

FortisBC indicates the NPV rate impact (over 25 years @ 10% discount rate) of the proposed AMI project has increased from-0.09% in the Original Application to 0.4% in the Amended Application.

Q66.1 Please confirm the rate impact analysis does not include the NPV impact of accelerated depreciation of existing meters. Please provide the cumulative NPV rate impact of the AMI initiative including the accelerated depreciation of existing meters, assuming existing meters are depreciated a) in Year 1, b) over two years, or c) over five years.

A66.1 The Company confirms that the rate impact analysis does not include the NPV impact of accelerated depreciation of existing meters. Please see Tables 66.1a, 66.1b, and 66.1c below.

Table 66.1a Summary of Revenue Requirements

	Expenditure / Impacts	2008	2009	2010	2011	2012	2016	2033
		($000s)						
1	Cumulative Capital Expenditure	568	17,170	37,507	37,586	37,647	37,642	37,387
2	Non-Project Costs	-	110	207	286	347	342	86
3	Total Operating Expense	-	-	(516)	(2,369)	(2,490)	(3,018)	(5,714)
4	Financing Cost	-	641	2,013	2,389	1,991	1,632	97
5	Total Revenue Requirement	-	151	1,187	11,807	(111)	(241)	(3,985)
6	Maximum Annual Incremental Rate Impact Over Previous Year	4.34%						
7	Net Present Value of Revenue Requirement	4,537						
8	One-Time Equivalent Rate Impact	0.15%						

Table 66.1b Summary of Revenue Requirements

	Expenditure / Impacts	2008	2009	2010	2011	2012	2016	2033
		($000s)						
1	Cumulative Capital Expenditure	568	17,170	37,507	37,586	37,647	37,642	37,387
2	Non-Project Costs	-	110	207	286	347	342	86
3	Total Operating Expense	-	-	(516)	(2,377)	(2,497)	(3,026)	(5,725)
4	Financing Cost	-	641	2,013	2,537	2,131	1,615	80
5	Total Revenue Requirement	-	151	1,187	6,437	5,788	(270)	(4,017)
6	Maximum Annual Incremental Rate Impact Over Previous Year	2.36%						
7	Net Present Value of Revenue Requirement	4,359						
8	One-Time Equivalent Rate Impact	0.14%						

Table 66.1c Summary of Revenue Requirements

	Expenditure / Impacts	2008	2009	2010	2011	2012	2016	2033
		($000s)						
1	Cumulative Capital Expenditure	568	17,170	37,507	37,586	37,647	37,642	37,387
2	Non-Project Costs	-	110	207	286	347	342	86
3	Total Operating Expense	-	-	(516)	(2,369)	(2,490)	(3,018)	(5,714)
4	Financing Cost	-	641	2,013	2,625	2,392	1,563	50
5	Total Revenue Requirement	-	151	1,187	3,226	3,038	(323)	(4,835)
6	Maximum Annual Incremental Rate Impact Over Previous Year	1.19%						
7	Net Present Value of Revenue Requirement	4,224						
8	One-Time Equivalent Rate Impact	0.14%						

National Regulatory Research Institute

Advanced Metering Infrastructure: What Regulators Need to Know About Its Value to Residential Customers

Nancy Brockway

February 13, 2008

08-03

Acknowledgements

This report would not have been possible without the in-depth work of many utilities, regulators, and experts in energy planning and economics who have studied the costs and benefits of advanced metering infrastructure and demand-responsive tariffs over the last several years. They have taken responsibility to push the envelope of energy policy, and have taken the risk that decisions made in circumstances of uncertainty may eventually prove to have been suboptimal. I wish to thank the members of the Edison Electric Institute listserv on AMI, the low-income energy listserv sponsored by the National Consumer Law Center, and the participants in the NARUC Consumer Affairs Staff Subcommittee listserv. I have benefited from the dialogue these forums have provided to debate issues in the field, and from the specific comments of Ralph Abbott, Barb Alexander, Dan Delurey, Eric Englert, Ahmad Faruqui, Steve George, Ed Grey, Marcel Hawiger, Rick Hornby, Steve Huso, Roger Levy, Catherine McDonough, Jay Morrison, Mike Oldak, and Lisa Wood on the penultimate draft of the report. Janis Dillard and others from the staff of the Delaware Public Service Commission (for whom I worked as a consultant during early phases of research on this report) have consistently provided valuable insights on all things utility. I am solely responsible for any mistakes in the report, including any errors in the summaries of the detailed work done by the utilities and evaluators on pilots discussed in this report. Leah Goodwin's expert editing and formatting have made this a readable document. I wish to give particular thanks to Scott Hempling, Director of NRRI, for his constant encouragement to focus on the merits of the debate, rather than the competing agendas of the debaters. The views expressed here are my own, unless otherwise noted.

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Executive Summary

I. Introduction and Overview

This report began as an effort to understand who has the better argument: those opposed to "advanced metering infrastructure" (AMI) as a demand response tool, and those supporting AMI for the same reason. As our understanding of the AMI issues has evolved, the paper has evolved. The report now casts a wider web.

We provide regulators with a general framework for evaluating an electric utility's request for recovery of the costs of implementing an advanced metering infrastructure.[1] We do return to, and examine in depth, the disputes between consumer advocates who oppose AMI and environmentalists, and utilities who support AMI. We place these disagreements in the context of a model for analyzing the overall costs and benefits of AMI.

In the first section, we provide an overview of the report and define AMI. We use the definition of advanced metering infrastructure that the Federal Energy Regulatory Commission (FERC) Staff uses:

> ...a metering system that records customer consumption (and possibly other parameters) hourly or more frequently *and* that provides for daily or more frequent transmittal of measurements over a communication network *to* a central collection point. AMI *includes* the communications hardware and software and associated system and data management software that create a network between advanced meters and utility business systems and which allows collection *and distribution of information to* customers and other parties such as competitive retail providers, in addition to providing it to the utility itself.[2]

We also note a number of additional issues that a regulator will want to resolve before determining whether to approve AMI cost recovery. For example, the report does not discuss whether pre-approval of AMI (or any other utility investment) is warranted. Similarly, the report does not try to recommend a useful life of AMI components for use in a net present value evaluation. Such a value is key to the evaluation and likely to be the subject of disagreement among experts and the parties.

[1] Gas utilities can and do implement AMI, although they cannot use all the functionalities of AMI that an electric utility can, particularly remote connection and disconnection. The gas demand response initiatives using AMI are likely to be different from those of an electric utility as well. This report does not discuss AMI in a gas utility setting.

[2] *FERC Staff Report*, Appendix A (Glossary) (emphasis supplied).

In the first section we also distinguish AMI from other technologies and systems that are sometimes confused with AMI, and from other technologies and systems that can be used to provide demand response offerings to consumers without the cost of a complete AMI system. We introduce a recurring theme: AMI is one way, but only one way, for a utility to offer time-varying utility prices and induce demand response. Proponents and opponents of AMI agree on this point.

There are numerous configurations of advanced metering, communications networks, and back-office applications and software installed in an AMI project. Each will give the utility different sets of functions, and different associated costs. To provide an example, we put forward the California definition of functions that must be included for a project to be considered AMI:

Figure ES-1: AMI Minimum Functionality (after California PUC Requirements)

a. Supports implementation of time-varying tariffs for:
   1. Residential and small commercial customers (under 200 kW):
      i. Time-of-Use (TOU) rates;
      ii. Critical Peak Pricing[3] with fixed notification (CPP- F) and CPP with variable or hourly notification (CPP-V) ;
      iii. Flat/inverted tier rates.
   2. Large customers (200 kW to 1 MW) on an opt-out basis:
      i. Critical Peak Pricing with fixed or variable notification;
      ii. Time-of-Use rates;
      iii. Two part hourly Real-Time Pricing.
   3. Very large customers (over 1 MW) on an opt-out basis:
      i. Two-part hourly Real-Time Pricing;
      ii. Critical Peak Pricing with fixed or variable notification;
      iii. Time-of-Use Pricing.

b. Allows collection of usage data at a level of detail that supports customer understanding of hourly usage patterns and how those usage patterns relate to energy costs.

c. Provides customer access to personal energy usage data with sufficient flexibility to ensure that changes in customer preference of access frequency do not result in additional AMI system hardware costs.

d. Compatible with applications that (1) use collected data to provide customer education, energy management information and customized billing; and (2) support improved complaint resolution.

e. Compatible with utility system applications that promote and enhance system operating efficiency and improve service reliability, such as remote meter reading, outage management, reduction of theft and diversion, improved forecasting, workforce management, etc.

f. Capable of interfacing with load control communication technology.

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[3] The "critical peak" consists of the small number of hours during a year during which most or all of the available generation resources are needed to meet demand.

II. Structure of an AMI Cost-Benefit Analysis

In the second section, we provide a recommended structure for evaluating whether to allow AMI costs in utility rates. We note that AMI is a major investment, like other major uses of utility capital and management focus. In general, a utility investment must be used and useful in the service of its customers, its benefits must exceed its costs, and it also must be more cost-effective than all reasonable alternatives that exist for accomplishing the same functions or achieving the same benefits.

To evaluate AMI under these principles, a regulator will of course need reliable information on the costs and benefits of AMI for the utility in question, as well as the costs and benefits of reasonable alternatives.

In this second section, we set out a number of the publicly available estimates of AMI investment cost. As the name implies, an advanced meter infrastructure is more than an advanced meter, capable of recording usage over discrete time periods. Depending on the configuration of the particular AMI, the type of communications network installed, the meter functionalities, the back-office system, and software changes made to use certain functionalities, AMI can cost anywhere from $100 to $525 per meter.

The second section also introduces the benefits of AMI. Two major cost savings opportunities are associated with AMI, and AMI makes a number of service improvements possible.

Operational savings made possible by implementation of an advanced metering infrastructure come primarily from reduced meter reading costs and other substitutions of AMI technology for more costly labor. For utilities that do not already use automated (e.g. drive-by) meter reading, these operational savings represent well over 50 percent of all cost savings attributable to AMI. We provide a number of examples of the kinds of operational benefits claimed by utilities for AMI in their service area, with breakouts of the relative contribution of the specific cost savings to the overall operational cost reduction.[4]

Resource cost savings from using AMI would result from and be determined by the extent of persistent demand reductions achieved by introducing dynamic pricing and demand response programs implemented using AMI technology. The costs of providing energy (generation costs) vary tremendously from hour to hour within a day. Across the country, 10 percent of the peak demand is concentrated in the top 1 percent of the hours of the year. If a cost-effective means could be found to shave some of this critical peak, great resources savings would be possible. Time-varying pricing is one tool that arguably can induce such peak load reductions. As discussed in some depth in Section III of the report, much of the debate over AMI centers on whether residential customers can and will respond to such time-varying pricing.

[4] We also note that one possible source of cost savings, remote connection and disconnection, can have adverse impacts on low-income customers, among others, and is barred by statute or rule in some states.

Service improvements include faster and more precise identification of outages, more accurate metering and billing, and the like.

III. Impacts of Time-Varying Prices on Residential Customers

In Section III, we focus on whether and to what extent residential customers can and will reduce demand in response to price signals and demand response programs implemented using an advanced metering infrastructure. We will also consider whether the response of different subsets of residential customers varies, such that AMI might be beneficial for some residential customers and pose risks to others.

Utilities and AMI supporters claim that AMI will enable utilities to lower societal energy costs over the long term, lower bills for many customer segments in the short-term, and improve service. A fundamental benefit of AMI, they argue, is the ability it provides the utility to offer all customers rates that vary with the time of usage, and thus better match the costs of the system. This in turn, they argue, will induce customers to reduce usage during critical periods of especially high cost. A number of respected consumer advocates oppose the implementation of AMI. They argue that AMI costs more than it saves. In particular, they argue that residential customers cannot take advantage of time-varying prices. Indeed, they claim, low-income and other vulnerable customers will be hurt if forced to take service under rates that are higher during peak periods of high-cost days. They also note that less expensive means to induce load reduction are in use today.

To explore who has the better argument, we look at three major pilots of various forms of time-varying pricing in recent years, each of which was extensively studied and evaluated in published reports. The three pilots are (1) the California Smart Pricing Pilot (CA SPP); (2) the Commonwealth Edison/Community Energy Cooperative Energy-Smart Pricing Plan™ (ESPP); and the Ontario Smart Price Pilot (OSPP). After describing these pilots, we look at each for evidence that answers six key questions:

Figure ES-2: Key Areas of Uncertainty Explored in This Report

1. To what extent did residential customers on average reduce load in response to time-varying pricing in the three best-known pilots?
2. To what extent were the participants in the three pilots representative of residential customers, including particular subsets of such customers?
3. Did low-use or low-income customers respond to time-varying pricing?
4. How persistent, year after year, are the voluntary load shifts or reductions resulting from price signals, with or without smart meters?
5. If demand response tariffs are voluntary, what portion of residential customers is likely to choose such pricing?
6. What are the likely bill impacts from time-varying pricing, on average and for various subgroups of residential customers?

We summarize the answers to the key questions in Section IV. Before leaving Section III, we take a fresh look at the issues from the perspective of the regulator. We note that critical peak pricing and other time-varying pricing is likely to produce "winners" and "losers." We highlight the observation that the identity of these winners and losers will not depend solely on who can shift their usage off peak and avoid mandatory high peak (or critical peak) prices. Two other key factors will come into play. First, those with a relatively flat load shape should do well under time-varying pricing, as off-peak prices are typically lowered in order to keep the entire rate revenue-neutral. As it happens, low-income customers tend to be low-use customers, and low-use residential customers tend to have a relatively flat load shape. Except to the extent that incremental AMI costs overwhelm the benefit of the flat load shape, low-use customers (low-income included) should do well on time-varying pricing.

Second, the extent to which those who cannot shift load will do better or worse than the status quo depends on whether it is necessary to give 100 percent of the benefits made possible by the demand response to those who respond by lowering demand, in order to induce such demand response. If it is, then all customers would be paying for metering that only some customers will be able to use to their benefit. In such a case, the regulator will have a more difficult time convincing the public of the justice of a decision approving the recovery of AMI costs in rates, even if he or she determines that principles of cost-causation in rate design permit (if not require) such an outcome.

We close Section III with a list of the miscellaneous additional issues that a regulator will have to determine in the course of deciding whether to allow AMI costs in rates.

IV. Conclusions and Recommendations

In Section IV, we summarize the factual and policy conclusions reached from our research and analysis. Following is a summary of the answers we reach to our key questions:

Question	Summary Answer
1	Overall, residential customers displayed significant demand reduction in response to critical peak prices. Customers with direct load control devices (such as programmable communicating thermostats) responded at dramatically higher rates (up to 41 percent on critical peak days) than those without such automated control devices (between 10 percent and 15 percent on average). Response of residential customers on average to time-varying pricing varied from group to group, and time to time. In some cases, the mean response was higher than the median (some particularly strong responders pulled the average response up). It is likely that within the averages, individual customers and subsets of residential customers showed widely varying responses to critical peak pricing. Not all responses to time-varying prices were demand reductions. In at least one pilot, participants on average increased usage during certain critical peak periods, despite critical peak pricing and critical peak rebate pricing. In one pilot, half the participants showed no response at all. CPR customers responded to critical peak rebate opportunities, but showed a lower response to critical peak rebate opportunities than CPP customers showed to critical peak prices.
2	Participants in the time-varying pricing pilots were roughly representative of the customer base from which they were drawn, but it is not possible to rule out self-selection bias in the results. Participants were in some cases skewed towards higher-usage, higher-income customers.
3a	Lower-use customers in general reduced their load by lower percentages than higher-use customers. One analysis of California results showed that low-use customers did not reduce loads at all in response to critical peak pricing; another analysis of the same data showed low-use customer response, but not at the same level as for high-use customers. Results were mixed for residents of multifamily buildings, who tend to be among lower-usage households - in the ESPP and OSPP, such customers at times responded more strongly than those in single-family homes. In the California SPP, residents of multi-family homes responded to critical peak pricing, but at lower levels than residents in single-family homes. Low-use customers of all income groups had the highest bill reductions, not counting AMI costs.
3b	Lower-income customers in general reduced load by lower percentages than higher income customers. Results are not definitive about the impacts of CPP or PTR on low-income customers, because income bands in pilot evaluations were not well defined. In one pilot showing strong low-income response, practically all the response came from a handful of customers. In the CA SPP, lower-income/high-usage customers increased usage on critical peak days.
4	The pilots do not provide a basis for estimating how persistent the observed demand responses will be year over year. Past experience with time-varying rates is discouraging on this point, but perhaps not indicative of likely persistence of response over time, given today's less expensive metering and demand response technologies, the ability to isolate high peak

	prices to a narrow set of critical peak hours, and the ability to program end uses to respond to prices communicated by the utility.
5	Pilots to date provide no useful information regarding the likely participation rates of voluntary time-varying tariffs. Optimistic estimates of 20 percent migration to opt-in time-varying rates and 80 percent opt-out retention rates have no basis.
6	None of the pilots provides readily available information on likely bill impacts of AMI, in that none addresses the allocation of incremental customer costs and time-varying resource cost savings to participants and non-participants. This omission is a major gap in the research to date, and hampers regulators trying to anticipate how an overall positive cost-benefit calculation for AMI will translate to specific customer groups. Findings of lowered bills from time-varying pilot prices must be discounted by the fact that the cost side of the equation ignored AMI costs. Even without counting AMI costs, 20 percent or more of the CA SPP participants on all pilot rates saw higher bills. In the Ontario SPP, 25 percent of the participants had no bill decrease, or had bill increases, on the time-varying tariffs. Among customers with higher bills in the Ontario SPP, CPR customers had larger increases than CPP customers.

The results of several pilots, then, show that residential customers, on average, have responded strongly to various types of dynamic pricing. Critical peak pricing, in particular, has shown promise as a demand response tool for residential customers generally.[5] Further, customers with uses suitable for load control, such as central air conditioning, and who have smart thermostats installed to automate the demand response to price signals, responded much more strongly than other groups. However, not all pilot participants reduced load, not all groups reduced load on average in every circumstance analyzed, and in some cases, participants' critical peak loads went up during the pilot.

Bill impact information is necessary if for no other reason than to gauge popular acceptance of more dynamic pricing. Here, the pilot data is virtually useless, because none of the pilots reflected those incremental AMI costs that would be counted against incremental demand response resource cost savings. Even without reflecting this added cost, some customers experienced high bill increases at certain points in the pilots. For a variety of reasons, low-income high-use customers in at least one pilot experienced large bill increases, again without considering the bill increases associated with that portion of AMI not offset by operational savings. As well, only time will tell whether the results observed in these pilots will persist into the future.

Because of (1) the uncertainties over persistence of demand response under critical peak pricing or rebates; (2) the lack of specific information from the pilot reports about the identity of

[5] This report does not focus on time-of-use rates, as such rates did not call forth the strongest responses in the pilots, and also can readily be implemented without investing in a complete advanced metering infrastructure.

possibly vulnerable customers (making it hard to determine whether, and if so, how to mitigate potential harm to such customers); (3) the relatively small portion of estimated AMI costs that can be covered by operational benefits in some cases; and (4) questions about the extent to which those responding to critical peak prices must receive the entire benefit of their load reductions, leaving no benefit for other customers, it is not possible to conclude that AMI makes sense in all circumstances. Greater efforts to induce persistent critical peak demand reductions are necessary, as future costs of capacity and energy are on track to keep going up. Whether AMI makes sense as the tool to incent demand response is very much open to question.

Turning finally to the recommendations, we begin by acknowledging the uncertainties facing a regulator in evaluating AMI and its alternatives. Most of the thorny issues require answers about what the future will bring. There are two ways a regulator can resolve these uncertainties and decide what action to take: move forward now, or wait until the experience of states with AMI and time-varying pricing helps narrow the uncertainties about the life-cycle costs of AMI and the resource benefits AMI can help induce. Neither involves authorizing further pilots.

What remains is a choice about whether to lead consumers in taking on the AMI risks that time-varying pricing will not succeed as a demand response tool and that AMI costs will prove greater over time than now forecast.

There are enormous challenges facing regulators, electric utilities competitive suppliers and ultimately electricity consumers today: high incremental generation construction costs, high fuel costs, high incremental transmission and distribution infrastructure costs, new and potentially quite expensive environmental constraints on generation, to mention only a few. Some of these pressures are not likely to abate, and will instead intensify over time. Against this background, it could make sense for a regulator to pay some public goodwill and political capital out in the form of leadership in the area of demand response and operations technology, taking the risk that the uncertainties about the costs and benefits of AMI will be resolved against AMI's cost-effectiveness.

It is not likely to require as much political skill to persuade utilities, consumers and other stakeholders to accept time-varying pricing as it has been historically. According to the pilot results, participants expressed satisfaction with pilot time-varying pricing by overwhelming majorities. Some of the historic common sense arguments against time-varying pricing need to be re-examined. Contrary to common assumptions about who can take advantage of peak pricing signals, residential customers in more than one dynamic pricing pilot have successfully lowered demand in response to critical peak pricing. Even low-use and low-income customers have, on average, lowered usage significantly in some circumstances. Low-usage customers also benefit from a relatively flat load shape. It is, in principle, possible to identify and assist customers who are both low-income and high-usage, to prevent them from experiencing major bill increases as a result of an AMI investment and subsequent implementation of time-varying prices.

On the other hand, a regulator could look at the same data and conclude that, at least until some years pass (and demand response from California customers and those in other jurisdictions implementing time-varying pricing remains strong), demand response should not be counted towards the benefits of AMI. In the meanwhile, the regulator should encourage other forms of utility demand response activity.

For example, the dramatic results for customers with programmable communicating thermostats (producing demand responses 50 percent higher than prices alone) may well be achievable by direct load control, implemented without the interposition of AMI's advanced meters and sophisticated communications networks. Similarly, critical peak pricing and rebates could be offered on a targeted basis to customers most likely to respond strongly, using advanced meters but not the rest of the AMI technology. Especially where a utility already has harvested labor savings from automating the meter reading function, AMI may not be cost-effective, and these other alternatives should be pursued.

The best course will vary from service area to service area, from utility to utility, from time to time. Doing nothing about demand response is not an option, in light of the enormous costs that a small amount of peak load shaving can avert. This author tends to be cautious, and considers that utilities seeking approval to recover major investments in rates without a reliable cost-benefit justification should shoulder the risks associated with the uncertainties that remain. With this background in mind, the following are some recommendations that emerge from this review of issues surrounding AMI for residential customers:

Figure ES-3: Recommendations

1. Where automated meter reading has already been installed, regulators should not authorize cost recovery of Advanced Metering Infrastructure until results from California and other states with widespread AMI and time-varying rate options demonstrate persistent and large resource savings from time-varying rates.
2. Regulators should require a full analysis of the merits of AMI whenever a utility requests cost recovery.
3. Where the analysis of costs and benefits of AMI leaves doubt about its net value, regulators should require utilities to take the risks associated with such uncertainty, if they wish to move ahead with AMI.
4. Regulators should not require further pilots before implementing or deciding not to implement AMI.
5. Regulators who have decided not to authorize expenditures on AMI at this time should require periodic updates from utilities concerning levels and persistence of demand responses among customers of utilities with ongoing pilots or full-scale implementation of AMI, and updated information available as to the impact of such AMI investments and any time-varying pricing plans implemented using such AMI on residential customers generally, and on especially vulnerable customers in particular.
6. Regulators should require utilities to develop and implement aggressive, cost-effective demand-response programs, including efficiency as well as Direct Load Control.
7. Regulators should seek access to underlying data on pilots that have been operated to date, and arrange for this data to be analyzed to develop reliable

estimates of (a) bill impacts of AMI and time-varying pricing on different groups of residential customers, and (b) the extent to which customers reduced their demand by taking steps that would be difficult to take year after year.

Advanced Metering Infrastructure: What Regulators Need to Know About Its Value to Residential Customers

I. Introduction

A. Overview of this report

1. Purpose: Define AMI and recommend methods of assessment, with a focus on residential customers

Utility regulatory commissions across the United States are increasingly seeing utility proposals for investments in so-called "advanced metering infrastructure" (AMI). Utilities and AMI supporters claim that AMI will enable utilities to lower societal energy costs over the long term, lower bills for many customer segments in the short-term, and improve service. The passage of the Energy Policy Act of 2005 has also spurred interest in AMI. Under Sections 1252(e) and (f), it became the policy of the United States to encourage "time-based pricing and other forms of demand response."[6] Proponents of AMI point out that, while other technologies can support time-based pricing and demand response, AMI is one vehicle a utility can use to implement such pricing and demand response.

A number of respected consumer advocates oppose the implementation of AMI. When AMI supporters have proposed AMI investments or pilots of pricing innovations that AMI could support, regulators typically have had to evaluate and decide a number of contested issues. This report will provide a framework that regulators can use to analyze the merits of AMI for an electric utility,[7] with an emphasis on the impact of AMI and its demand-response uses on residential customers.

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[6] EPACT 2005 requires that each state regulatory authority conduct an investigation and issue a decision on whether it is appropriate for electric utilities to provide and install for their customers time-based meters and communications devices, which enable such customers to participate in time-based pricing rate schedules and other demand response programs (Section 115(i) of PURPA). As of July 1, 2007, twelve Commissions had completed the review required under Section 115(i), and another 27 had dockets open. Federal Energy Regulatory Commission (FERC), *2007 Assessment of Demand Response and Advanced Metering, Staff Report* (FERC Staff Report) September 2007, 27.

According to the FERC Staff, by that date, two states had decided to adopt the new PURPA standard, eleven states had decided not to adopt the standard, and four states had deferred the decision. Ibid., Appendix E. The FERC report also collects citations from the various states of legislation, docket filings, Commission orders, and other activities on advanced metering, demand response, and real time pricing initiatives.

[7] AMI can be and is being installed by gas utilities. The relative costs and benefits are different in some respects from those that affect the merits of AMI for electric customers. This

We will begin by defining AMI, and distinguish AMI from other advanced metering and demand response technologies that some utilities have implemented. We then turn to the question of how a regulator determines whether a utility investment, such as AMI, qualifies for cost recovery in rates. In principle, regulators must decide whether the benefits of AMI, such as utility cost savings, outweigh the incremental costs, and are larger than net benefits achievable through alternatives to AMI.

To evaluate AMI under these principles, a regulator will of course need reliable information on the costs and benefits of AMI for the utility in question, as well as the costs and benefits of reasonable alternatives. To begin the analysis of the information presently available on these topics, we will briefly describe the costs a utility will typically incur to implement an advanced metering infrastructure. We will next outline the categories of cost savings and other benefits that a Commission typically will want to assess in determining whether to approve the recovery of AMI costs in rates. We will introduce the two major sources of savings attributed to AMI (operational savings and resource cost savings), and touch on the service improvements possible with an advanced metering infrastructure.

Operational savings made possible by implementation of an advanced metering infrastructure come primarily from reduced meter reading costs and other substitutions of AMI technology for more costly labor. **Resource cost savings** from AMI would result from, and occur proportionate to the extent of, persistent demand reductions achieved by introducing dynamic pricing and demand response programs implemented using AMI technology. **Service improvements** include faster and more precise identification of outages, more accurate metering and billing, and the like.

We will focus on a particular aspect of the estimation of AMI-related resource cost savings. Specifically, we will address whether and to what extent residential customers can and will reduce demand in response to price signals and demand response programs implemented using an advanced metering infrastructure. We will also consider whether the response of different subsets of residential customers varies, such that AMI might be beneficial for some residential customers and pose risks to others.

In considering the merits of implementing AMI, Commissions have been faced with sometimes heated debate over its value as a tool to support residential demand response and thereby lower system resource costs. There is no dispute that shaving peak usage on a sustained basis can lower system costs. Meeting peak demand, of which 10 percent is concentrated in the top 1 percent of hours of the year, requires the installation of generating plants that are idle most of the year, and whose fuel costs are higher than fuel costs for other plants. Their costs-per-kilowatthour-generated are the highest of all plants. For this reason, if a cost-effective means can be found to shave demand off the peak in the long-term, considerable resource savings should be possible.

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memorandum will focus on the electric utility application of AMI, but the general principles of analysis are applicable to gas utilities.

Many economists and rate designers suggest that offering (if not requiring) pricing that varies in relation to changes in the cost of supplying customers would induce many customers to shift their usage patterns in order to use power at less expensive times. Shifting power from the highest-cost peak times to lower-cost shoulder or off-peak times would then lower the average cost of the generation used to supply customers. AMI includes technologies that can be used to offer such time-varying pricing options.[8]

Proponents and opponents of AMI investments disagree about the extent of achievable demand response. They disagree particularly on whether residential customers, and certain vulnerable customers in particular, can and will respond to time-varying pricing by reducing their demand. They further disagree about whether there are cheaper ways to obtain these valuable demand reductions. To help Commissions sort through the assertions made about the potential of AMI to facilitate resource savings from residential customer demand response, we will take an in-depth look at pilot studies of time-varying pricing in three jurisdictions and assess whether they can be relied on to predict how time-varying pricing will work in other states, as well as over time.

We will also explore the net effect of time-varying pricing on residential customers, and on vulnerable customers within the residential class. We will examine what information there is from the pilots concerning the impact of AMI investments on different types of residential customers, including available information on bill impacts. Regulators will want to understand the differences in how AMI and different pricing structures offered using AMI affect residential customers as a whole, as well as their impact on particular groups of residential customers, to satisfy themselves that recovery of AMI costs from all customers is fair and that the public will accept it.

We will touch on some of the alternate means of incenting demand response among residential and other customers. A utility's case for recovery of AMI costs must demonstrate that it has explored all reasonable alternatives to AMI, and that AMI is the least costly of the workable alternatives.

This report will not give equal weight to all the issues that a regulator must examine on the way to determining whether to permit AMI costs to be recovered in rates. Rather, after laying out the overall structure of a regulatory analysis, we will focus on some issues that have dominated the debate over AMI among AMI supporters and consumer advocates who oppose AMI. From this perspective, we will explore in depth what is known about the following questions:

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[8] It cannot be repeated too often that AMI is just one set of technologies that can be used to make time-varying pricing possible.

Figure I: Key Areas of Uncertainty Explored in This Report

1. To what extent did residential customers, on average, reduce load in response to time-varying pricing and direct load control in the three best-known pilots?

2. To what extent were the participants in the three pilots representative of residential customers, including particular subsets of such customers?

3. Did low-use or low-income customers respond to time-varying pricing?

4. How persistent, year after year, are the voluntary load shifts or reductions resulting from price signals, with or without smart meters?

5. If demand response tariffs are voluntary, what portion of residential customers is likely to choose such pricing?

6. What are the likely bill impacts from time-varying pricing, on average and for various subgroups of residential customers?

The outcome of an AMI cost-benefit analysis will vary from utility to utility. It is not defensible to state that AMI is always a net benefit or always a net loss for consumers. The evidence available to date does allow us to categorize the major drivers of AMI cost and benefit, and use them to provide recommendations about the direction Commissions should take if their goal is to reduce utility costs and improve utility efficiency, if not also improve utility services. It does not, however, provide a neat formula for deciding whether to approve cost recover of AMI investments.

2. Omitted topics that will require regulatory consideration before approving cost recovery for AMI and time-varying pricing

This report will not try to answer every question a regulator may have about how to evaluate an AMI proposal. It also will not provide guidance on how to determine all benefits or costs of AMI investments. For example, this report will not address the potential for load response among commercial and industrial customers. Further, the report does not attempt to evaluate in detail the cost estimates offered by utilities in support of their initiatives, or the useful life of such investments.

This report also will not address questions of prudence, or externality costs and benefits, although such considerations should occupy a regulator's attention. In particular, we note that some environmentalists and utilities tout time-varying pricing as a means of reducing energy usage and thus emissions, while others stress that the usage reductions on peak can lead to higher emissions if cleaner gas-fired or hydro generation on peak is replaced by additional coal-burning off-peak.

The report will not address concerns recently raised about the exposure of networked utility systems, including links into customers' homes, to hacking and other "cyber"-intrusions.[9] It will also not explore the arguments advanced by some AMI proponents that installation of the advanced metering infrastructure will provide a platform on which new and as-yet-unknown services and functions can be implemented.

In addition, this report will not address whether and under what circumstances regulators should grant pre-approval of any or all AMI costs. A Commission may have different standards for approving the utility's cost recovery at different points in the path from conception to implementation. In this report, we will focus on the overall question of costs and benefits, rather than the distinctions a Commission may draw between the proofs needed for pre-approval and those needed for the inclusion of a plant in service into the rate base (and recognition of expenses actually being incurred).

Nor will we attempt to resolve all the issues that arise when demand response saves a competitive supplier in resource costs, but the competitor's retail contract for such supply does not provide for a flow-through of those savings to the retail customer. This situation commonly occurs in the case of default service arrangements in retail competition states, under present approaches to default service procurement and contracting. Work-arounds are possible eventually through revision of the standard contracts, but the specifics of such contract changes are beyond the scope of this report. Similarly, this report assumes that the utility has a portfolio optimization requirement. In states where the utility not only has no such obligation, but is in fact barred from performing such functions, the pros and cons of AMI installation will have to take into account the split between the distribution utility and the entity or entities responsible for generation planning. AMI proponents justify its costs based on benefits reaped on the distribution and generation sides, not just one or the other.

This report will not address whether fairness, or economic efficiency in the abstract, require or justify time-varying prices. Nor will the report address the pros and cons of AMI, interval metering, and two-way communications in facilitating retail competition.

Finally, we will not try to quantify the relative costs and benefits of a direct load control program, targeted to certain customers a utility expects are likely to be able and willing to allow the utility to reduce their peak loads in response to incentives. Direct load control can be accomplished without AMI, and arguably at less cost, but may produce somewhat greater reductions when supported by AMI. A full analysis of the merits of AMI will need to address these issues as well.

[9] Ellen Nakashima and Steven Mufson, "Hackers Have Attacked Foreign Utilities, CIA Analyst Says," *Washington Post*, January 19, 2008, A04.

Each of these issues warrants further research, research that this report hopes to stimulate. For those interested in exploring these issues further, we provide a reading list at the end of the report.

B. What is AMI and what can it do?

1. Advanced metering is only part of AMI

"Advanced metering infrastructure," as defined by the Staff of the Federal Energy Regulatory Commission (FERC). is:

> ...a metering system that records customer consumption (and possibly other parameters) hourly or more frequently *and* that provides for daily or more frequent transmittal of measurements over a communication network *to* a central collection point. AMI *includes* the communications hardware and software and associated system and data management software that creates a network between advanced meters and utility business systems and which allows collection *and distribution of information to* customers and other parties such as competitive retail providers, in addition to providing it to the utility itself.[10]

AMI is not limited to advanced meters, but refers to an entire infrastructure that ties advanced meters to a data management system and from there to other utility business systems. "AMI" is not (yet) a term of art. There is no single, universally accepted definition of the components that, taken together, constitute an advanced metering infrastructure.

When analysts, utilities, regulators, stakeholders and others use the term "advanced metering infrastructure" in the case of electric utilities, they do tend to refer broadly to a collection of hardware (e.g. meters and computer processors), software (e.g. billing system computer programs) and other elements that taken together permit the utility to perform certain functions. Below is a list of components that most people have in mind when they use the term:

Figure II: Components of an Advanced Metering Infrastructure

1. Interval meters, that can record and store usage data on hourly or more frequent basis.

2. Two-way communications network between meter and supplier/utility that can send usage data from the meter to the utility; and send pricing, load control and other signals from the utility to the customer's premises.

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[10] *FERC Staff Report*, Appendix A (Glossary) (emphasis supplied).

3. A meter data management system (MDMS), that can handle large amounts of information concerning individual customer usage profiles.

4. Revised utility operational software, that can make use of the granular usage data produced through the meters, communications network, and meter data management system.

When AMI is implemented, it is typically implemented system-wide, although the roll-out of the new meters may be done in stages. Eventually, when AMI is fully implemented, advanced meters are in all premises, and the communications systems are in place to connect all of them with the utility's new data management system. An AMI system loses some of its value if it is restricted to certain segments of the customer base. Unless all customers are metered and billed off the same data management system, for example, the utility may have to maintain more than one billing system. It is possible to implement advanced metering, without more, by customer type. But it is not sensible to implement the entire advanced metering infrastructure (AMI) on a piecemeal basis, installing new meters and communications links for some customers but not all, and then running two meter data managements systems and two sets of back-office software (one for those customers with AMI, and the old one for customers who do not yet have AMI).

There are a large number of variations of technology within the rubric of advanced metering infrastructure. A utility will design an AMI system to include the technologies needed to perform, at a minimum, a desired set of functions at the least cost, while also leaving open the option to add on to or modify the system as the technology evolves.[11]

2. AMI supports a variety of utility functions

Not all utilities with AMI systems use them to perform all the functions that such systems, at least in theory, can perform. It can be useful, when considering a multi-million dollar investment such as an AMI, for a utility to design the system so that it will be capable of adaptation to new functions over time. With this in mind, the California PUC recently promulgated a list of the functions that an AMI system must enable a utility to perform, if the utility wishes to recover the costs of an AMI investment.[12] The Commission has not held itself

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[11] Edison Electric Institute has published a valuable primer on AMI technologies, prepared by Plexus Research, Inc.: *Deciding on "Smart" Meters: The Technology Implications of Section 1252 of the Energy Policy Act Of 2005*, a report prepared for the Edison Electric Institute (EEI), September 2006.

[12] Assigned Commissioner and ALJ Ruling, in the docket captioned "Order Instituting Rulemaking on Policies and Practices For Advanced Metering, Demand Response and Dynamic Pricing (Advanced Metering Final Decision)," *Rulemaking* 02-06-001, February 19, 2004, 3-4. This Assigned Commissioner ruling has been endorsed and applied (as adjusted) in subsequent decisions of the full Commission. See, e.g., *Application of Pacific Gas and Electric Company for Authority to Increase Revenue Requirements to Recover the Costs to Deploy an Advanced*

slavishly to this list, but has required utilities to justify deviations from this list. The California PUC list is a good starting point for understanding the uses to which a utility can put AMI, and the functions that AMI typically performs for a utility.[13]

Figure III: AMI Minimum Functionality per California Minimum PUC

a. Supports implementation of time-varying tariffs for:
   1. Residential and small commercial customers (under 200 kW):
      i. Two- or three-period Time-of-Use (TOU) rates, with ability to change TOU period length;
      ii. Critical Peak Pricing[14] with fixed (day ahead) notification (CPP- F);
      iii. Critical Peak Pricing with variable or hourly notification (CPP-V) rates;
      iv. Flat/inverted tier rates.[15]
   2 Large customers (200 kW to 1 MW) on an opt-out basis:
      i. Critical Peak Pricing with fixed or variable notification;
      ii. Time-of-Use;
      iii Two part hourly Real-Time Pricing.
   3. Very large customers (over 1 MW) on an opt-out basis:
      i. Two-part hourly Real-Time Pricing;
      ii. Critical Peak Pricing with fixed or variable notification;
      iii. Time-of-Use Pricing.

b. Allows collection of usage data at a level of detail that supports customer understanding of hourly usage patterns and how those usage patterns relate to energy costs.

c. Provides customer access to personal energy usage data with sufficient flexibility to ensure that changes in customer preference of access frequency do not result in additional AMI system hardware costs.

d. Compatible with applications that (1) use collected data to provide customer education, energy management information and customized billing; and (2) support improved complaint resolution.

e. Compatible with utility system applications that promote and enhance system operating efficiency and improve service reliability, such as remote meter reading, outage management, reduction of theft and diversion, improved forecasting, workforce management, etc.

f. Capable of interfacing with load control communication technology.

Metering Infrastructure, Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure *(PG&E Final Opinion)***,** Decision 06-07-027 (CA PUC) July 20, 2006, at 23.

[13] The CPUC uses the term "price-responsive" rates, meaning rates designed to incent customers to respond by increasing or decreasing demand in response to a varying price. The report will use the more neutral term, "time-varying" prices.

There is no single list of AMI technologies and functions. New technologies and applications for AMI technology are rapidly being developed and brought to market. Some AMI proponents argue that there are uses for AMI that we have not even imagined yet, and whose benefits will far outweigh the costs of AMI installation.

For example, a number of technologies exist for performing the network communications functions, including power line pulse signaling, fixed wireless, internet signaling, and others. A regulator may be called upon to choose between particular technologies or even competing vendors. On the one hand, approving any particular form of AMI or any given source of AMI components provides some certainty about the scope of the AMI investment. A less prescriptive approach may make up in flexibility for the uncertainty of a specific AMI product's ultimate usefulness. In this regard, the California PUC has stated a preference for "open architecture" meters, which can "be accessed through multiple technologies such as radio and telephone."[16]

3. What AMI is Not: AMI vs. AMR vs. DLC vs. Smart Thermostats vs. PCTs

It is useful at the outset to note what AMI is *not.* AMI includes advanced metering (in particular, so-called interval meters, capable of recording and storing usage data at hourly intervals, if not at intervals as short as every 15 minutes). A utility can install interval meters, however, without installing an entire advanced metering infrastructure.

Some interval meters support static TOU pricing by means of a device added to the ordinary non-interval meter that allows the utility to collect usage information hourly. The utility then downloads the data monthly. AMI meters, by contrast, are also capable of sending and receiving meter and other data when called upon to do so, rather than merely storing it for monthly retrieval.

AMI is sometimes confused with "AMR," the acronyms being so close. AMR refers to automated meter reading, which in turn typically means remote meter reading, as by a hand-held device or a device on a utility truck driven by the meter location, picking up a signal from the meter to record the usage. AMR does not have to involve interval metering – the customer still could be paying a traditional, constant rate with the metering measuring only total usage in a month without regard to usage at particular times of day. Nor does AMR imply a two-way communications system and a meter data management system (MDMS). AMI, in contrast, can enable remote meter reading; in fact, the meter can be read from a central data storage and management location, by reading the signals communicated over the AMI network.

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[14] The "critical peak" consists of the small number of hours during a year during which most or all available generation resources are needed to meet demand.

[15] California's standard flat-rate electricity price design for residential customers is an inverted block rate, with five blocks, or tiers.

[16] Advanced Metering Final Decision, 19.

Direct load control (DLC) is another demand response tool that can be implemented using parts of an advanced metering infrastructure, but that does not require AMI. A utility can implement DLC using technology other than AMI. With direct load control, a customer agrees to allow the utility to turn off or down one or more end-uses at the customer's premises. Utilities and residential customers typically use DLC to cycle off air conditioners, using a radio or power line frequency signal sent to a device attached to the air conditioning control unit in the home. They also use DLC to reduce peak demand from pool pumps and water heaters. DLC is defined in the FERC Staff Report as follows:

> A demand response activity by which the program operator [the utility, typically] remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice. [17]

Utilities can use AMI as a convenient network to signal DLC devices at times of peak demand, but AMI is not required to perform this function. Utilities can set up a dedicated communications network to connect their control center with those customers taking service under a DLC rate; they need not implement an advanced metering infrastructure for all customers in order to provide DLC for some. Conversely, a utility can install AMI without installing direct load control devices on customer end uses.

Finally, "smart thermostats" are not a required component of AMI, although they may offer benefits for demand response in addition to those possible with AMI alone. "Smart" or "programmable communicating thermostats" (PCTs) are the devices attached to the air conditioner or other end use that receives signals from the utility. In a DLC program, the supplier signals the smart thermostat to lower or raise the end use device's draw on the electricity system. The signal could also be a notification of the beginning or the end of a high-cost peak period. The customer can pre-program the thermostat to respond to such signals, as by raising the temperature setting, or cycling the air conditioner off. For a customer to receive demand response signals from AMI's communications network, she would need (a) the interval meter networked to a load control or signaling system, and (b) a PCT attached to the end uses she wanted controlled.[18]

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[17] *FERC Staff Report*, Appendix A (Glossary)

[18] Readers should be also aware of so-called "gateway" devices, which act somewhat like routers by taking the pricing signals from the utility, then distributing those signals over a home area network (HAN) to various end uses in the house, permitting each end use to respond according to the instructions pre-programmed by the customer into the associated PCT or similar smart device. PG&E has recently asked the California PUC for approval of cost recovery for the installation of gateway devices and HAN technology. See *PG&E Upgrade Application*.

II. The Structure of an AMI Cost-Benefit Analysis

A. A cost-benefit analysis for AMI has the same analytical components as a cost-benefit analysis for other major utility investments

To justify an AMI investment, like any other investment, a utility will have to show that the investment will lead to lower costs, or to improved services, or both, relative to no investment and relative to alternative investments. The value obtained from the investment must at least exceed the cost, and must exceed the value of alternative investments.

A utility may present to the Commission its own internal business case for AMI. In a business case, the utility will limit the analysis to a comparison of the utility's costs of the investment versus the utility cost savings made possible by the investment and the improved value of service to the customers. In some jurisdictions, Commissions will also consider factors outside the business case, such as environmental or other benefits allegedly made possible by the investment.[19]

Whenever a utility seeks to reflect costs in rates, not only must the benefits of the particular investment decision exceed the costs, but the choice must be the best among a reasonable set of options available to the utility for the purpose(s) at the time. To make a case for AMI cost recovery, then, a utility will need to prepare information for the regulator demonstrating the following:

Figure IV: Elements of the Rationale for a Prudent Investment

1. The need or needs for the functionalities provided by the investment.
2. The array of reasonable alternatives available, including the one chosen, for meeting the needs.
3. The costs of each alternative.
4. The benefits of each alternative.
5. The relative costs and benefits of the alternatives compared.

As noted, the case for AMI will typically identify two primary needs for the AMI functionality: reducing costs of operation, and reducing the costs of meeting demand. Regulators should require the utility should be required to identify the scenarios it has identified and assessed for achieving these goals.

The types of costs and benefits included in a given jurisdiction's cost-benefit analysis will vary depending on the perspective from which the costs and benefits are measured. There

[19] In California, three years after the end of the SPP, stakeholders are still debating what cost-effectiveness test or tests should be used to evaluate demand-response pricing approaches. Ahmad Faruqui and Ryan Hledik, *The State of Demand Response in California*, Draft Consultant Report, April 2007, at 18-19. Available at: www.fypower.org/pdf/CEC-200-2007-003-D.PDF.

are five widely recognized cost/benefit perspectives[20] for evaluating the merits of an electric system investment in demand-side resources:

Figure V: California Standard Practice Cost-Benefit Tests

1. Utility Cost Perspective
2. Participant Cost Perspective
3. Non-Participant Bill Perspective
4. Total Resource Cost Perspective
5. Societal Cost Perspective

The elements of a benefit/cost analysis of demand response will vary depending on the perspective used to identify the benefits and the costs counted.

B. AMI is a major investment

AMI involves changing out 100 percent of residential and small commercial meters, replacing them with more expensive meters, installing a system-wide communications network, developing a new meter data management system, and rewriting software and business operations protocols to make optimal use of the new data and operational capabilities. While reliable estimates of the per meter cost for a full advanced metering infrastructure are hard to obtain,[21] estimates of AMI costs range from $110 per meter on the low end up to as much as $525 per meter. Plexus Research, Inc. developed an estimate for Edison Electric Institute (EEI) of the cost of various parts of an AMI implementation, pegging the per meter cost at between $200 and $525, depending on the functionality included:

> AMI costs ... typically include the following elements: AMI system hardware and software, new meters and meter-related utility equipment and labor, installation management and labor, project management, and IT support and integration. Costs for automated remote meter reading are approximately $100 to $175 per meter. Adding demand response

[20] California Public Utilities Commission and California Energy Commission. California Standard Practice Manual: Economic Analyses of Demand-Side Programs and Projects, October 2001, available at: http://www.cpuc.ca.gov/static/industry/electric/energy+efficiency/rulemaking/resource5.doc.

[21] One utility's consultant noted recently that much of the data on AMI component costs is proprietary, making it difficult to develop cost estimates that can be presented to a regulator, and the soundness of which a regulator can assess. Redacted Testimony of Dr. Gary Fauth, MW Consulting, on behalf of Central Maine Power Company, *Central Maine Power Co.: Chapter 120 Information (Post ARP 2000) Transmission and Distribution Utility Revenue Requirement and Rate Design and Request for Alternative Rate Plan*, ME PUC Docket No. 2007-215, May 1, 2007, at 5, 23.

components (e.g., customer signaling, load control, other demand response equipment) adds another $100 to $350 per site.[22]

For a system with 500,000 residential meters, then, the net present value cost of an AMI investment would likely fall in a range between $100 million and $262 million, net present value.

Pacific Gas & Electric (PG&E) plans to spend over $3 billion (net present value over twenty years) to implement AMI for its 9 million gas and electric meters. This investment represents an estimated cost of about $340 per meter.[23] The table below shows a breakdown of the costs PG&E estimated it would incur to install an AMI.[24]

Figure VI: PG&E Estimates of AMI Installation Costs

PVRR	Cost Category
$2.30M	Meters/modules QA; sample testing
$5.30M	Customer exceptions processing
$6.90M	Gas network and other installation
$22.60M	Marketing and communications
$43.40M	Other employee-related costs
$44.00M	Customer acquisition
$45.50M	Customer contact-related costs
$87.50M	Project management costs
$98.50M	Network materials
$99.10M	Electric network and Wide Area Network installation
$109.10M	Interval billing system
$119.10M	AMI operations
$129.30M	Meter operations costs
$135.00M	Risk-based allowance[25]

[22] Plexus Research, Inc., Deciding on "Smart" Meters: The Technology Implications of Section 1252 of the Energy Policy Act of 2005, Prepared for Edison Electric Institute, September 2006, at xii.

[23] PG&E Upgrade Application.

[24] PG&E Ex. 32, revised Table 10-1 (Revised 3/14/06), *PG&E AMI Final Opinion*, CA PUC Decision 06-07-027, July 20, 2006. As noted above, PG&E recently filed an "update" to its cost estimates, to include approximately $939 million in additional costs, on a present value basis. This update brings the total cost estimate to roughly $3.2 billion. *PG&E Upgrade Application*, at 1.

[25] The "risk-based allowance" is essentially a contingency allowance. *PG&E AMI Final Opinion*, CA PUC Decision 06-07-027, July 20, 2006, at 12. Decision available at: http://docs.cpuc.ca.gov/published/FINAL_DECISION/58362.htm.

PVRR	Cost Category
$155.60M	Interface and systems integration
$355.90M	Meters/modules installation
$799.20M	Meters and modules
$2,258.30M	**Original Total Estimated Project Costs**
$939.00M	Additional metering costs per *Upgrade Application*[26]
$3,197.00M	**Revised Total NPV Costs**

As can be seen, the cost of the advanced meters themselves, together with their installation, is about two-thirds of the total estimated cost of AMI for PG&E:

> $800 million for meters and modules, plus
> $940 million NPV in additional metering costs and related expenses, plus
> <u>$355 million in meter installation costs, for a total of</u>
> $2.1 billion out of the $3.2 billion total NPV estimated

Southern California Edison has estimated it will cost just under $2 billion to implement AMI in its service area, resulting in a per-meter cost of about $370.[27]

Not all experts in AMI are convinced the utility estimates represent the necessary costs of AMI investments. Stephen George and Michael Wiebe presented a lower-end cost estimate in a workshop presentation in August 2007. These consultants estimate the total capital cost per meter of an AMI installation will range from $110 to $130 per meter, with operating costs at 35 cents per month.[28] They note that the costs of advanced metering vary with the technology chosen, customer density, and other factors. Dr. Gary Fauth, testifying for Central Maine Power Company in its pending request for AMI cost recovery, stated that per-meter AMI costs from three other utilities (PPL, PG&E, and Bangor Hydro-Electric) ranged from $124 to $150 per meter.[29] Roger Levy also has noted that municipal AMI investments have been considerably less

[26] Such additional costs mainly relate to an additional $565 million capital investment in solid state advanced meters fitted with remote connect/disconnect switches, and installation of home area network (HAN) gateways. *PG&E Upgrade Application*, at 3-4.

[27] Most published cost estimates range between $100 and $200 per meter, but it is important to look at the specific proposals in any given case, to make sure that all costs are included in the estimate.

[28] Stephen S. George and Michael Wiebe, *Benefit-Cost Analysis for Advanced Metering and Time-Based Pricing*, Workshop, August 21, 2007, at 6. George and Wiebe state that typically less than half the costs of AMI are for the meters themselves. George and Wiebe do not include the incremental information technology investments that are needed for large-scale use of demand-responsive rates.

[29] Redacted Testimony of Dr. Gary Fauth, MW Consulting, on behalf of Central Maine Power Company, Central Maine Power Co.: Chapter 120 Information (Post ARP 2000) Transmission and Distribution Utility Revenue Requirement and Rate Design and Request for

costly than the utility estimates gathered here.[30] Levy also points out that AMI can be implemented without billing changes or DR program functions, in which case back office software changes or additions will not be as extensive nor as costly as those proposed by PG&E, for example. On the other hand, to the extent that a utility invests in AMI lacking the ability to support tariff changes, associated billing changes and demand response functionalities, a major potential source of benefit from the investment is presumably foregone.

C. AMI can provide large operational cost savings to a utility

1. Most operational savings come from replacing labor with information technology

One of the largest sources of cost reductions made possible by AMI is operational savings. The operational savings come in a number of forms:[31]

Figure VII: Categories of AMI Operational Savings

1. Remote meter reading
    a. Eliminates need for meter-reader to read meters
    b. Allows more frequent meter-reading
    c. Eliminates problems associated with estimated bills
    d. Improves meter reading accuracy, thus reducing meter disputes
2. Remote disconnection/reconnection (electric only)
3. Identification of outage locations
    a. Supports more rapid customer restoration time
    b. Eliminates need for customer outage reporting
    c. Allows more accurate dispatching of repair crews, with associated cost reductions
4. Improved tamper detection
5. Improved capacity utilization
6. Grid voltage and phase monitoring
7. Better load data for planning purposes

Alternative Rate Plan, ME PUC Docket No. 2007-215, May 1, 2007, Table GF-1, at 4. It is not possible, based on the information readily available, to square Fauth's estimate of PG&E AMI costs ($135 per meter) and the $340 per meter estimate derived by dividing the total net present value cost estimate of $3.2 billion by 9 million PG&E meters (or even the $250 per meter estimate that would result from dividing PG&E's earlier $2.3 billion cost estimate by its 9 million meters).

[30] Email from Roger Levy, January 30, 2008, with comments on draft report.

[31] See *In the Matter of the Commission's Combined Consideration of the Utilization of Advanced Metering Technologies Under 26 Del. C. § 100(B)(1)B. and the Implementation of Federal Standards For Time-Based Metering and Time-Based Rate Schedules Under 16 U.S.C. §§ 2621(D)(14) and 2625(I), Advanced Metering Report to the Delaware Public Service Commission*, prepared by Delmarva Power & Light Company, Division of the Public Advocate, and the Delaware Public Service Commission Staff, November 15, 2006, at 7.

In its recent AMI business case filing in Delaware, Delmarva Power & Light Co. (Delmarva) estimated that, depending on the size of expected demand response from time-varying pricing, the operational benefits of its proposed AMI implementation would be as much as 77 percent of the total savings it forecast, and at least 53 percent.[32] Before proposing to install an AMI with greater functionality, Pacific Gas & Electric Company estimated that almost 90 percent of its AMI investment would be recovered through operational benefits (the proportion may be closer to 2/3 with the added cost). Southern California Edison and Sempra estimate that they will recovery roughly 50 percent of their AMI costs through operational benefits.[33]

2. AMI permits service quality improvements

Many of the functionalities that AMI makes possible not only save a utility in operational costs, but also improve the quality of service provided to customers. For example, more frequent meter-reading gives customers better information on their changing usage and electricity costs, in turn making it easier for customers to budget for such costs. Similarly, by eliminating the need for estimated bills, AMI makes it possible for customers to have timely and accurate readings of their actual usage, and receive bills that do not require adjustment. This accuracy in turn helps with electricity cost budgeting. Estimated bills also create many billing disputes that are not only costly to the utility, but aggravating and time-consuming for customers. More timely and accurate meter readings should also remove a common source of distrust of the utility by consumers.

Identifying outage locations, dispatching crews more efficiently, and restoring customers more rapidly would provide an enormous benefit to consumers. As regulators are well aware, outages, slow restoration time, and lack of good information regarding outage time is a source of considerable frustration to consumers.

Improved tamper detection helps protect those whose electricity is being stolen.

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[32] *In the Matter of Delmarva Power & Light Company's Blueprint for the Future Plan for Demand-Side Management, Advanced Metering, and Energy Efficiency*, Report for Delaware: Advanced Metering Business Case Including Demand-Side Management Benefits, filed August 29, 2007, Del. P.S.C. Docket No. 07-28. It is axiomatic that the higher the assumed demand response resource benefits, the lower the percentage the operational savings represent of the total benefits.

[33] *Ibid*. The differences in the percent of savings attributable to different utility operations is likely due to differences in the cost of these functions to each utility using existing resources (largely labor). Staff of the California Public Utilities Commission, Division of the Ratepayer Advocate analyzed why PG&E estimated AMI operational savings at levels much higher than those forecast for comparable operational changes with AMI by San Diego Gas & Electric. Among other things, the analyst observed, labor costs at PG&E were significantly higher, and avoiding those costs accordingly brought PG&E a larger benefit than was the case for the Southern California utilities. Marshall Endberry, *Meter Reading Benefits,* Division of Ratepayer Advocates, Chapter 7, available at: http://www.dra.ca.gov/docs/electric/SDGandE/A0503015_Ch7_MeterCost.pdf.

Grid voltage and phase monitoring should lead to improvements in voltage stability and distribution reliability. Better load data for planning purposes will give the public information they can use to participate in the great debates under way today regarding the kinds of investments needed to meet electric power needs going forward.

3. Different utilities have different operational savings and benefits

The lion's share of AMI operational savings comes from eliminating labor costs for meter-reading. This result is consistent across the utilities that have filed business cases with their commissions. The existence and relative amount of other benefits appears to vary from utility to utility.

For some utilities, the second-highest savings come from eliminating labor costs for connection, disconnection, and reconnection. On the other hand, utilities in Oregon considering the implementation of AMI have advised the Oregon Commission that they do not consider remote disconnection/reconnection cost-effective for their systems.[34] Pacific Gas & Electric in California forecasts remote turn-on/shut-off functionality to produce 5 percent of the total operational cost reductions from implementing AMI. Utilities thus have provided regulators with widely varying estimates of the cost savings available from the elimination of manual connection and reconnection of metered premises.

Improved billing accuracy and timeliness, reducing off-cycle meter reading costs, and allowing asset optimization together produce savings taken together that are large enough to have a noticeable impact on AMI cost/benefit calculations. Other operational benefits together make up a smaller percentage of the total savings attributable to the substitution of AMI technology for labor costs. The exact distribution of estimated operational cost savings will vary from utility to utility.

[34] Email to Consumer Affairs listserv from Phil Boyle, Manager, Customer Services and Information, Oregon Public Utilities Commission, October 25, 2007.

The table below shows how two utilities identify the share of major AMI savings associated with different functions:

Figure VIII: Major Categories of Operational Savings, Two Utilities

Major Categories of Operational Savings,
As Estimated By Two Utilities[35]

Benefit Category	% of Total Operational Savings	
	Utility A	**Utility B**
Eliminate manual meter-reading costs	53%	60%
Electric Transmission and Distribution	10%	3%
Meter Operations	5%	n/a
Reduce Customer Contact Costs	2%	1%
Improved billing accuracy/timing/reduce theft	11%	9%
Reduced software license, hardware expense	2%	1%
Remote Turn-On/Shut-Off	5%	25%
Other Employee-Related Costs	11%	n/a
Reduced Equipment Replacement Costs	1%	n/a

The two utilities in the example forecast that over half the expected operational cost savings will come from eliminating manual meter reading costs. A utility's present costs, and thus its potential savings from AMI, will likely vary from utility to utility. Nonetheless, the estimates provided by the two utilities in the above example give a good sense of the type of information on operational benefits that a utility is likely to present in a business case for AMI.

4. Operational savings sometimes come at a cost to the customer

When is a benefit not a benefit? Critics of AMI argue that the ability to disconnect a customer remotely, without the opportunity for personal contact when a technician comes to the home to disconnect the meter, denies customers an opportunity for personal intervention that otherwise exists.[36] It thus puts particularly vulnerable customers at greater risk. Some states

[35] One of the utilities whose estimates are reflected in this chart is PG&E, and the other is a utility on the East Coast, information as to which was derived from data in a confidential filing. To ensure that no confidential data is revealed, the specific identities of the two utilities are withheld, and only percentage contributions to overall savings are shown.

[36] A director of consumer affairs for one Northeast state public utilities commission noted in an email listserv discussion of the issue in October, 2007, that her commission relies not only on in-person disconnection, but in-person meter reading as well, as a tool to ensure that shut-ins and other vulnerable customers have human contact with their utilities providers at least once a month.

require an electric utility to attempt an in-person notification of impending disconnection, whether to provide an opportunity for the customer to remedy the default and prevent disconnection, or to alert the utility to the possibility that the customer has been unable to understand and respond to collection efforts, and will be put at risk by a disconnection.[37]

For example, New York State by law prohibits remote disconnection, even of electricity, and requires that utilities allow customers to pay their bills at the time of disconnection to prevent the disconnection.[38] The New York Public Service Commission has recently pointed to this statutory "last knock" provision in orders denying immediate approval of AMI proposals by two electric utilities in the state.[39] Similarly, the Michigan Commission requires more than one telephone notice attempt, and phone lines must be disconnected in person.[40]

The requirement of in-person contact is by no means universal today, however. Indeed, recently promulgated AMI rules in Texas require that the utility have the ability to perform remote disconnection.[41] Utilities in Idaho and Iowa have filed proposals to institute remote disconnection.[42]

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[37] Remote disconnection and reconnection is not safe in the case of gas utilities. Disconnection results in the pilot light on appliances and furnaces going off; if the gas is restored without the pilot light gas source first being turned off, gas can build up and when the pilot is lit, an explosion can result. Gas utilities send a trained technician to perform disconnections and reconnections, to avoid such accidents. The inability to use remote connection and disconnection in the case of gas utilities is a key reason why the economics of AMI are different between gas and electric utility applications.

[38] See New York Public Service Law, Article 2, Section 3(b) and (c).

[39] PULP, *PSC Requires More Study Before Allowing Major Investment in "Smart Meters,"* January 11, 2008, available at: http://www.pulpnetwork.blogspot.com/.

[40] Recently a 90-year old Michigan woman died of hypothermia, and her mentally disabled 65-year old daughter suffered frostbite, when their electricity was disconnected this winter. The Commission and the utility are investigating whether the customer received in-person notification, as required by Commission. According to the dead woman's family, she had become more forgetful recently; she had apparently forgotten to pay her bills, although she had sufficient funds. Preventing such tragedies is one reason why some Commissions require in-person disconnection. The Associated Press, "Utility looks into death of Vicksburg woman, 90, after power shut off," originally published January 2, 2008, available at: http://www.battlecreekenquirer.com/apps/pbcs.dll/article?AID=/20080102/NEWS01/301020015/-1/bb.

[41] 16 Texas Administrative Code §25.130(g)(1)(D)**,** published November 10, 2006, for effect May 10, 2007, pursuant to Public Utility Regulatory Act (PURA) §39.107 as amended by House Bill (HB) 2129, 79th Legislature, Regular Session (2005).

[42] Iowa's proposal would include the ability to impose a service limiter on an account, as permitted by Iowa Administrative Code, § 20.4(23).

Utilities promoting remote disconnection/reconnection argue that, despite the claimed importance of in-person contact, customers generally will benefit as the utility will be able to reconnect service more quickly using AMI technology, and will be able to reconnect during non-business hours, an expensive proposition with in-person reconnection. Resolution of this issue is a policy decision regulators must make. There is little data on the extent to which avoided disconnection and reconnection costs would be associated with foregoing "last knock" opportunities for vulnerable customers to avoid disconnection.

D. Customers can reduce system resource costs by reducing demand, especially at times of high system demand

Section C dealt with operational cost savings. In this subsection we turn to resource savings attributable to demand response.[43]

While some utilities have implemented AMI without implementing time-varying pricing or other demand response initiatives, for most utilities it is likely that operational cost savings (even coupled with the value of improved services) will not cover the full cost of an AMI investment. Utilities point to additional cost savings that they can obtain by using AMI to support time-varying prices, which are intended to induce customers to reduce demands at times of high system costs, thus lowering system resource costs.

By "resource costs," we mean here the various costs associated with the production function: generation capacity and energy costs, and transmission and distribution capacity costs. Some states include externality costs such as emissions[44] in their determination of resource costs, and some states include customer demand response and non-utility generation as system resources.

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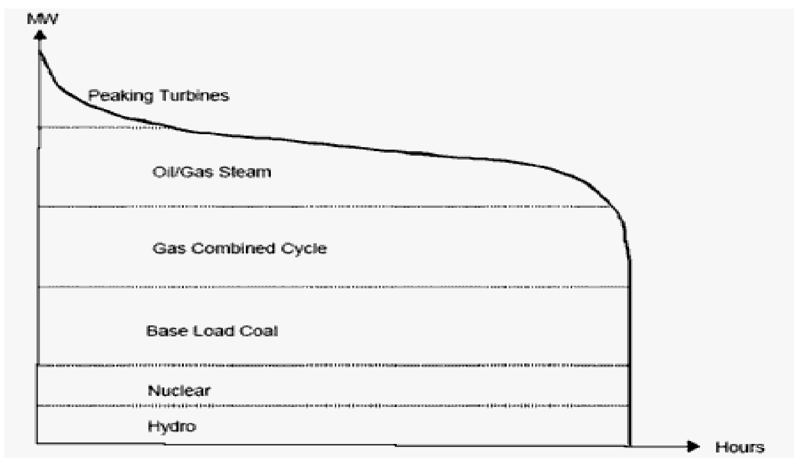
[43] Traditionally, utility analysts would not use the term "resource costs." Costs associated with meeting customer energy and capacity needs were broken down by the various utility functions, such as operations, maintenance, transmission, distribution and generation. Since the late 1980s, regulators and utilities in a number of states have adopted the term "resource costs" to identify not only these utility costs, but costs incurred by others to meet customer needs. Sometimes these additional costs include externalities such as environmental or social costs.

[44] There is an ongoing debate among analysts as to whether demand response initiatives create environmental benefits such as reduced emissions. Prominent advocates of demand response as a tool to foster environmental benefits acknowledge that reducing peak demands can actually increase emissions in certain situations. For example, in systems with gas or hydro plants at the margin, and coal as the baseload fuel, backing off the cleaner peak fuels increases the proportion of kilowatthours served with more polluting coal generation. David Nemtzow, Dan Delurey and Chris King, "The Green Effect: How demand response programs contribute to energy efficiency and environmental quality," *Public Utilities Fortnightly*, March 2007, at 44. Estimating the change in emissions from demand response requires careful analysis of the specifics of each situation.

The primary resource cost that can be deferred or avoided via persistent AMI-supported demand response is the cost of incremental generation capacity.[45] Looking at an annual load duration curve, one can see that there is a small number of hours when load is quite low (such as the hours during the dead of each night), a large number of hours in the year when there is a steady demand for power, a large number of hours with a varying amount of load above the base, and a very small number of hours when the system is running at or very near its maximum capacity. The drawing below[46] shows a hypothetical load curve of a utility with several types of generation, indicating the hours in the year the different plants are likely to be dispatched, given their cost characteristics. As can be seen, the portion of the year when peakers are brought on line to meet peak demand is quite small:

Figure IX: Annual Load Durations, w/Plant Dispatch Periods by Generator Type



To meet base load needs, utilities select plants with low running costs, albeit high capital costs. The utility will run these plants 24 hours a day, most days of the year. It is usually less expensive to do so than to run plants with lower capital costs, but higher operating costs, for such extended periods.[47] For the hours of highest demands, the peak hours, a utility will build a plant with high operating costs, but low capital costs. Such "peakers" are more cost-effective for the purpose of meeting demand during a few hours of the year while sitting idle the rest of the time.

[45] See, e.g., *The Power of Five Percent*, and In the Matter of Delmarva Power & Light Company's Blueprint for the Future Plan for Demand-Side Management, Advanced Metering, and Energy Efficiency, Report: Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs, prepared by the Brattle Group for Pepco Holdings, Inc., filed September 21, 2007, Del. P.S.C. Docket No. 07-28.

[46] This chart was copied from http://www.ec.gc.ca/cleanair-airpur/caol/canus/IPM_TECHNICAL/ipm_technical_report/images/figure2_3_e.gif.

[47] The breakpoint between load levels most economically served by different types of plants will vary with the particular system and its loads, but all systems were historically built along these general lines to minimize unit costs.

For loads in between these two extremes, planners select so-called "intermediate" plants, whose relative capital and running costs are less skewed than either baseload or peakers, and which can be turned on and off as needed to follow changing load requirements at the least cost to the system.

System operators dispatch plants in order of unit production cost to meet growing or declining load. The higher the load on the system, the higher the cost per kilowatthour of the plants brought on line. Dispatching plants according to their relative unit costs of operation is called "merit order" dispatch. The objective is to minimize the total cost of supplying power to meet the changing demands on the system over time.

Note that the situation is slightly different in the case where a regional transmission organization (RTO) or Independent System Operator (ISO) performs the dispatch function according to the results of an energy market. In such a system, plants will not be dispatched in "merit order" (i.e., on the basis of their cost to the unit owner). Rather, aside from "self-scheduled units" that are dispatched at the request of the owner (and that are not bid into the energy market for the hour in question), the RTO/ISO dispatches all units whose bids were less than or equal to the market-clearing price.[48] The suppliers, optimizing their portfolios in response to incentives created by an energy market (and perhaps a capacity market and markets

[48] If an RTO/ISO system does not have as much demand in the particular hour as the system operator assumed when it cleared the market (and thus determined which plants would be dispatched), and does not need generation from the plant whose bid determined the market clearing price, the system operator resets the market clearing price to the level of the next lowest bid (which is now the highest bid of those needed to run in that hour). Should the system in the particular hour require more resources than those the system operator forecast when it ranked the bids and thus selected the units to be dispatched, the RTO/ISO must acquire additional resources for reliability purposes. Under the Standard Market Design (SMD) used by the major RTOs and ISOs to run their markets, the system operator selects such additional generation as follows:

> Generation offers and load bids into the Day Ahead market. The Day Ahead Market clears to minimize total cost to serve load plus reserves, much like the day ahead commitment under the interim markets. However, since the Day Ahead Market is voluntary and financial, not all load may bid into it, consequently, there may not be enough capacity on-line to assure reliable operation.
>
> To assure reliability, the ISO performs a Resource Adequacy Assessment. The objective of the Resource Adequacy Assessment is to assure sufficient capacity is on-line (or off-line and available) to meet load plus reserves. If additional capacity is needed to meet reliability the ISO does not commit based on energy economic merit order. Instead, the ISO commitment is based on minimizing the costs of bringing a unit on-line.

Source: ISO-NE Frequently Asked Questions available at: http://www.iso-ne.com/support/faq/other/why_is_my_unit_not_running.pdf for ancillary services), tend to bid into the energy market in such a way that the resulting dispatch looks similar to a merit order dispatch, but it will not be identical.[49]

The exact amount, sources and relative share of savings from lowering incremental demand will vary from state to state and region to region, depending on such factors as the extent to which capacity is available to meet forecast demands, and the mix of plants and fuels used to generate power in the area.

Published estimates of demand-related resource savings also depend critically on assumptions about how many customers will respond to price signals, to what extent and for how long. The state of our understanding of the extent of and persistence of demand response to dynamic pricing is the subject of Section III.

The method analysts typically use to estimate avoided costs is a standard avoided cost calculation. Note, however, that in retail competition systems, where most electricity customers receive their power under standard offer service provided by suppliers under contract, the avoided system costs will not translate into reduced prices in the short term, unless the contracts specify that savings from demand response programs are somehow identified and flowed through to customers.

In addition, demand responses must be reliably persistent over time, or planners and market overseers will not reflect them in the development and pricing of new generation capacity. In New England, for example, ISO-NE establishes the Installed Capacity Requirement (ICR) for the entire region for a specific "power year" approximately 3 years in advance of that power year (e.g. in 2007 it sets ICR for 2010).[50] This overall capacity requirement is not affected by events in the next two years, unless they are part of a reliable pattern that planners can take into account in their forecasts of loads and resources. A load serving entity (e.g. a utility) can reduce its proportionate share of the regional ICR if its loads in the year before the power year in question are lower, relative to the loads of other LSEs, than they were before. This adjustment, however, only occurs if other LSEs do not induce their customers to reduce loads proportionately, and in any event does not relieve the region as a whole from the ICR set two years earlier.

Similarly, the market value of capacity avoided by demand response will be effectively zero, unless the capacity reductions are persistent. Estimates of market price reduction assume that reductions in peak load by a limited number of participants in a demand-response program will result in a lower market price for capacity, which in turn will benefit all consumers. In order

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[49] These differences in likely dispatch patterns and associated supplier cost recoveries will affect the economic value of demand response, but likely not enough to change the analysis of the value of AMI. Our discussion here will use the example of a vertically integrated electric utility, owning and generating most of its own plant. The analysis can be adapted to the electricity market situation, but it will be easier to highlight the issues of interest here if we focus on the simpler case.

[50] Email to author from Rick Hornby, Synapse Energy Economics, January 31, 2008.

for the load reduction from the participants to cause the FCM to "clear" at a lower price, however, the planners at the regional transmission organization need to "see" enough years in which those actual load reductions occur to cause their econometric model to forecast a lower peak demand than it otherwise would.

The need of a regional transmission organization with a forward capacity market to set capacity requirements some years in advance, and to price that capacity, creates a need to establish the reliability of anticipated demand reductions. As Hornby explains, estimating the timing and magnitude of the market price reduction benefit requires some care. The planner in a vertically integrated system has a similar obligation to forecast reliably, so as not to underestimate the power requirements in future years. One can argue that the persistence of demand responses into the future is subject to no more uncertainty than the likelihood of demand growth over the same period, but whereas econometric models for forecasting demand have become commonplace, system planners and market operators have not had as much experience forecasting demand response, and calibrating their forecasts to improve reliability.

1. AMI can be used to support time-varying pricing and other demand response programs

There are a number of tariff designs intended to match unit prices of electricity to system costs at the particular time of use:

Figure X: Time-Varying Pricing Options for Residential Customers

1. Pure Critical Peak Pricing ("CPP")—time varying pricing on high-demand days only;

2. Pure Peak Time Rebate ("PTR")—a pay-for-performance offering that pays customers a certain amount for each kWh not used during peak periods on high-demand days;[51]

3. Critical Peak Pricing/Time of Use ("CPP/TOU")—time varying prices on both high-demand and other weekdays, with the highest prices occurring on high-demand days;

4. Time of Use ("TOU")—the same time-varying prices on all weekdays for a season or year;

5. Real Time Pricing—prices that change hourly in response to market conditions.[52]

[51] Peak Time Rebate is the current term—in the pilots, PTR was typically referred to as Critical Peak Rebate, or CPR.

[52] This list is taken from the rebuttal testimony of Stephen S. George , Ph.D. on behalf of Central Maine Power Company. *Central Maine Power Company: Request for New Alternate Rate Plan*, Maine PUC in Docket 2007-215, at 9-10.

A utility may use AMI to support a variety of pricing and other demand-response initiatives to induce customers to lower their usage at particularly high-cost hours.[53] Interval metering, a core component of AMI, allows a utility to charge different prices for electricity used at different times. A utility can use AMI to offer dynamic prices in addition to static TOU rates. A dynamic price is one that a utility can change in real time, or close to real time, to respond to changing system conditions. In theory, at least, a utility can use the two-way AMI communications network to signal the customer when the price changes, and to give advance notice of the change. Without AMI, utilities give signals over dedicated networks, by radio, power-line carrier and even by phone, fax, and email.

In addition to time-varying pricing, a utility can support other demand response programs using AMI. The two-way communications network included in AMI provides a system by which the utility can signal a customer's meter-designated end-uses (such as central air conditioning), instructing them to cycle off or use less power during the high-price period. The utility can use the same communications network to signal that the particularly high-price period has ended.

It is important to stress that utilities can—and have—supported such direct load control demand response programs without AMI. Demand response programs are related to AMI only inasmuch as they need and use interval data, and as the utility chooses to use the same two-way communications network it has installed as part of AMI to signal customers or their end-use devices as part of its DR tariff or program. AMI and DR are separate systems. AMI and technologies for signaling the customer are not necessarily parts of the same system, nor do they need to be physically linked.

2. AMI allows utilities to offer prices that more closely match changing system costs

Utilities and planners have offered customers (even residential customers) so-called Time of Use (TOU) rates[54] for many years. Ordinary TOU rates typically define two or three pricing periods during a day: peak and off-peak. Then prices are set to approximate the estimated costs of usage during the given periods.

Utilities, sometimes at the behest of the regulator, introduced such time-of-day Peak/Off-Peak TOU pricing for residential customers in the 1980's, at the time of the energy crises of the

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[53] Again, AMI is not necessary in order to implement a variety of forms of time-varying pricing. It is "sufficient" but not "necessary."

[54] Some analysts would include in the definition of Time of Use rates any rate that varied in unit cost depending on any measure of time, including seasonal rates, for example. Seasonal pricing is a form of demand response pricing. Seasonal pricing does not require advanced metering of any kind, but by the same token, it follows cost differentials in only a crude fashion. In this memorandum, we will restrict the use of the term Time of Use rates to tariffs in which prices change within a 24-hour period (technically, diurnal TOU rates).

day. Residential TOU rates eventually fell into disuse, in part because of public opposition,[55] and in part for lack of customer interest.[56] Long on-peak periods (sometimes as long as 12 hours) dampened customer interest. But the energy challenges facing society today, coupled with reduced interval metering costs due to evolving technology, have given new impetus to the effort to promote time-varying prices.

A utility today can implement narrower pricing periods than it could cost-effectively using earlier technology. This greater precision is valuable in pinpointing the times when changes in usage can bring the greatest changes in system costs. The ratio of cost reductions achieved for load reductions experienced becomes higher as the system nears its overall peak. The pricing approaches used to incent demand reductions thus focus on peak usage. The utility can use the AMI network to give customers notice a day in advance or even a few hours in advance of a particularly high-cost ("critical peak") period, and to signal its end. Prices for such narrow periods can be set to match the costs of such narrow periods.

Off-peak prices in a TOU tariff are lower than the standard flat rates. As a result of the differentiation of prices by time of usage, a customer with relatively lower usage on peak than the average will enjoy lower overall bills on TOU rates than on the underlying flat rate, assuming no change in time of usage. Conversely, a customer with a higher relative on-peak usage than the average for the class will see higher bills on TOU rates, unless the customer can move usage off that peak time period.

By more narrowly defining the high-priced periods, utilities can offer customers time-varying prices with shorter periods of very high prices. This approach has the benefit of greater convenience and customer acceptance than traditional TOU prices with broad peak periods. To take advantage of these improvements in tariff design, utilities are increasingly offering so-called critical peak pricing.

Critical peak pricing (CPP) is a form of TOU pricing. Under critical peak pricing, the price for power is as much as 5 or 10 times higher during the critical peak than during other times, while the price is correspondingly lowered during the remaining 80 percent to 90 percent of the hours. Not every day will have a critical peak. The critical peaks are those few hours[57]

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[55] See Kenneth Gordon, Wayne P. Olson, Amparo D. Nieto, *Responding to EPAct 2005: Looking at Smart Meters for Electricity, Time-Based Rate Structures, and Net Metering*, prepared for Edison Electric Institute, May 2006, at p. 7, n. 12.

[56] Ralph E. Abbott, "Time-of-Use Rates: Sideburns and Bellbottoms?," *Energy Markets*, July/August 2005, pp. 6-8.

[57] At least for residential customers, utilities have generally not attempted to price power differently for time periods shorter than a couple of hours, although the technology of advanced metering theoretically could enable a utility to define a separate price for periods as small as 5 minutes. Several utilities in Washington State recently completed a pilot demand-response program in which price signals were given every five minutes, and a customer's present willingness to pay given amounts for designated "comfort settings" determined the customer's demand response. See note 204, below.

during the year when system load is at its highest, and the system is strained to its maximum capacity. A utility will notify customers on the CPP rate the day before or the morning of a critical peak event.

These peak periods represent a tiny fraction of the total hours in a year, but it may be possible to avoid significant resource costs if load can be shaved from or moved off of such times on a sustained basis over time. In most parts of the United States, the period of maximum electricity demand spans only 1 percent to 2 percent of the hours of the year. Put another way, "80 to 100 hours account for roughly 8 to 12 percent of the maximum or peak demand."[58] A critical peak tariff will define critical peak for pricing purposes as some subset of these hours.

There is no single definition of the critical peak periods. The designation varies by utility, and is determined not only by system resource requirements but also by rate design considerations (such as customer acceptance of a limited number of hours of very high critical peak prices). Critical peak events will typically be limited to a small number of hours in the day of the critical peak (e.g. 2 to 7 in the afternoon). CPP tariffs usually contain a limitation on the number of critical peak events and/or critical peak hours a utility may call in any given year (or season).[59]

As a variant on CPP, a utility can also offer critical peak rebates (CPR), sometimes called a peak-time-rebate, or PTR. Under PTR tariffs, a customer would be charged according to the same underlying tariff the typical customer of that class faces. However, the utility notifies the CPR customer of an impending critical peak, and the customer has the opportunity to reduce usage (relative to a defined baseline) during that critical peak, and receive a rebate for such reductions.

The most-often discussed CPR/PTR tariff calculates the rebate as the reduction in usage from the baseline times a rate equal to what would be the critical peak price for those customers on CPP rates. In the Ottawa Hydro CPR pilot, for example, the customer paid the ordinary 10.5 C¢/kWh TOU rate for all peak usage at or above the baseline during critical peaks. If the customer reduced critical peak usage 1 kWh per hour (*i.e.*, 1 kW) below the baseline for 3 critical peak hours, he would be credited with a rebate equal to 3 kWh times 30 cents, or 90 cents for that critical peak day.

[58] Ahmad Faruqui, Ryan Hledik, Sam Newell, and Hannes Pfeifenberger, "The Power of Five Percent*,"* *The Electricity Journal*, Volume 20, Issue 8, October 2007, at 69.

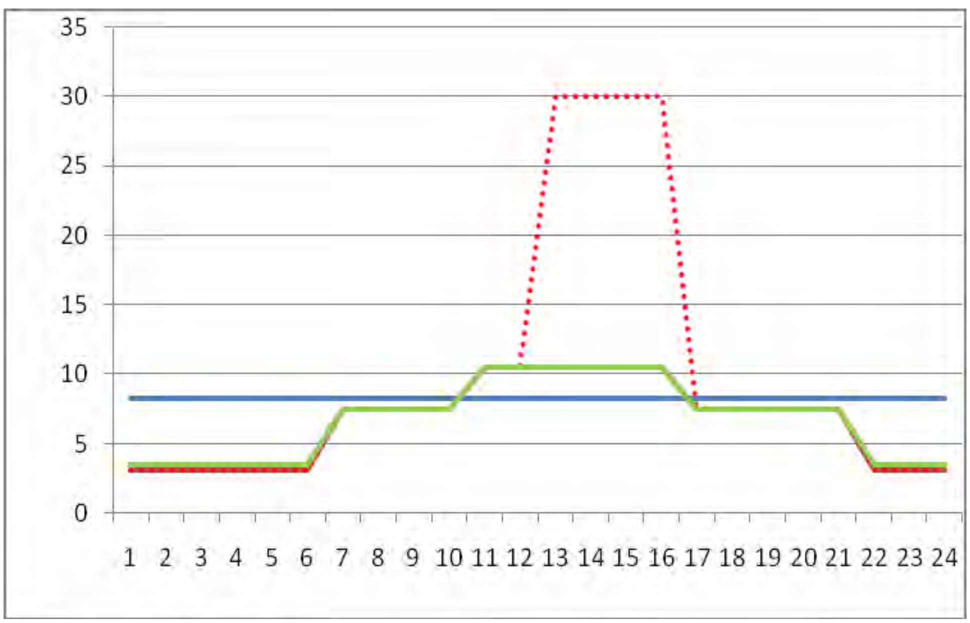
[59] Other versions of a critical peak tariff include Extreme Day Pricing (the critical peak price applies all 24 hours of the critical peak day; the number of critical peak days is limited, and the utility notifies customers the day ahead) and Extreme Day CPP (the critical peak price applies to the critical peak hours of the critical peak day, and the flat rate applies to all other hours of all other days – there is no TOU rate included). See Ahmad Faruqui, *Pricing Programs, Time of Use and Real Time*, Encyclopedia of Energy Engineering and Technology, 1:1, 1175 – 1183, available at: http://dx.doi.org/10.1081/E-EEE-120041453.

The picture below shows an example of critical peak pricing applied during a critical peak day. As the system is stressed by repeated days (and nights) of hotter-than-usual weather, unit costs approach their highest levels of the year. Under the Critical Peak Pricing tariff assumed in this example, the utility can call a critical peak event for the particularly costly hours on Wednesday and Thursday.

The picture gives a good sense of the differential between standard flat rate and Time-of-Use prices and CPP prices. During those critical peaks, per kilowatthour prices for customers on the CPP tariff are 6 times as high as the standard flat rate, and even 3 times as high as the peak rate on the standard TOU tariff. These extraordinarily high prices (e.g. 30 cents/kWh) are in effect for CPP customers for only a few hours on each critical peak day; the utility is typically limited in the number of critical peak events it can call. CPP customers, then, do not face these very high prices for more than 80 to 100 hours in the entire year.

Figure XI: Chart of CPP/TOU/Flat Rate Prices on a Critical Peak Day

Cents/kWh



Hours

The closer a utility can price usage for any given hour to the actual system costs incurred by customer usage during that hour, the more dynamic the rate. In the pilots described in Section III below, California has recently experimented with forms of critical peak pricing in which customers receive notice of the specific critical peak price on the day before or the day of the critical peak event, depending on the tariff. Commonwealth Edison and a Chicago neighborhood cooperative piloted a form of real-time pricing. Utilities in the Northwest have recently conducted a pilot in which participating customers were notified in real time (5-minute intervals) of changing price events, and engaged in a real-time market to determine the value of demand reductions (or the price of buying through) at the designated peak.[60]

III. Impacts of Time-Varying Pricing on Residential Customers

A. AMI analysts disagree over whether residential customers can benefit from AMI

Regulators considering a request for cost recovery of AMI are likely to have to resolve a number of disagreements between AMI proponents and AMI opponents. Some of these disagreements concern fact assertions. Some related to conclusions that different parties draw from the same facts. Finally, some disagreements relate to policy differences. In this section, we list the major areas of contention. In later sections, we examine the evidence available to resolve factual disagreements, and discuss policy implications.

1. AMI critics argue that residential customers will have bill increases, but that many will not be able to avoid high peak prices

Critics of AMI argue that implementation of an advanced metering infrastructure will increase costs for most residential consumers, without offering them a realistic way, through demand response, to avoid incurring those costs. The Utility Reform Network (TURN), a California consumer advocacy group, argues that low-use residential customers in particular do not have enough load to shift shifted away from the peak periods; thus they will pay for the meters but not get the cost reductions. Conversely, TURN argues, those with loads high enough to load-shift away from on-peak or critical peak prices will not bother to do so, because their high incomes enable to them to bear the cost of avoiding the inconvenience of load-shifting.[61]

Barbara Alexander, a noted consumer affairs expert, seconds these arguments. She makes the following assertions in support of her opposition to AMI and time-varying pricing:

1. [T]he use of more dynamic pricing methods assumes that every customer has the ability to respond to hourly or daily price signals.

2. This ability is obviously easier for higher usage residential, commercial, or industrial customers who have greater flexibility for reduction or shifting the usage away from expensive peak hours and taking advantage of the option to lower bills and experience benefits…

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[60] For more information on the Pacific Northwest GridWise™ Demonstration Project, see note 120, and accompanying text, below.

[61] Marcel Hawiger and Gayatri Schilberg, *Advanced Metering Infrastructure: What Happened to Demand Response?*, presentation to Joint Agency Workshop, September 30, 2004.

3. These options are not as easily available to customers with a fairly constant usage profile or who use such a low level of electricity that there is not a great deal of elasticity in their ability to reduce or shift usage, at least without suffering some potential discomfort or harm to health.

4. Such may be the case with many residential customers and is more likely the case with limited-income and payment-troubled residential customers who typically use less electricity than their higher-income neighbors.

5. The penetration of more energy intensive appliances is lower for limited-income customers….

6. On average, limited-income customers reside in housing units [that]…require less electricity to light, heat, or cool….

7. However, those [limited-income] customers with poorly insulated dwellings, in need of repairs, or who rely on less efficient and older appliances, are the least able to … take actions to reduce their energy usage due to their limited income.

8. Also, low-income renters may lack control over appliances provided by landlords….

9. These factors suggest that limited-income and payment-troubled customers are not as likely to be able to take actions in response to price signals that are available to higher-income customers….

10. The only practical option available to these customers is to do without or make changes in their lifestyle or family schedules to avoid using electricity at certain times of the day, even when that may adversely impact their health.

11. Finally, older consumers may need a constant level of heat or cooling to maintain a safe body temperature and "doing without" in the middle of a heat wave in order to avoid higher bills may result in dire health and safety consequences.[62]

Advocates who oppose AMI and real-time pricing also assert that there are less expensive ways to obtain demand response benefits and associated system cost reductions.[63] For example, TURN argued in California that the proposals to move forward with advanced metering and real-time pricing "ignored many tools already available to achieve demand response." Turn also

[62] See Barbara Alexander, *Smart Meters, Real Time Pricing, and Demand Response Programs: Implications for Low Income Electric Customers (Smart Meters),* Update, May 30, 2007. Available at: http://www.pulp.tc/Smart_Meters__Real_Time.pdf.

[63] Gerald Norlander, "Not So Smart? High Tech Metering May Harm Low Income Electricity Customers," (*Not So Smart)* Public Utility Law Project Blog, Monday, April 16, 2007. Available at: http://pulpnetwork.blogspot.com/2007/04/not-so-smart.html.

contended that air conditioner recycling programs[64] had provided some of the most reliable demand reductions in the nation.[65]

Critics have also argued that existing meter investment will be stranded, further burdening consumers. AMI opponents argue that customers should not be required to pay for the un-depreciated costs of existing metering and related hardware and software. Critics also contend that AMI metering and communications technologies are relatively new and untested, and that wholesale AMI investments should not be made—or at least not funded by ratepayers—given the immature state of the technologies and the market.[69]

2. Proponents of AMI as a tool to support time-varying pricing say AMI opponents are wrong on both facts and policies

Proponents of AMI as a tool to support time-varying prices say that opponents have the facts and the policy wrong. The key counterarguments of AMI proponents are listed below.[70]

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[64] An air conditioner cycling program is a form of direct load control. Customers who take service under the program agree to allow the utility to turn off their air conditioners, or raise the temperature setting, during times of system peak demands. They are called cycling programs because typically the utility will turn off only a quarter of the air conditioners subject to the program at a time, cycling through the entire pool in an hour but not requiring any one participant to go without air conditioning for a long time.

[65] As cited in the Interim Opinion in Phase 1 Adopting Pilot Program for Residential and Small Commercial Customer (Interim Opinion), in the docket captioned "Order Instituting Rulemaking on Policies and Practices For Advanced Metering, Demand Response and Dynamic Pricing," California PUC Rulemaking 02-06-001, June 6, 2002, available at http://docs.cpuc.ca.gov/published/final_decision/24435.htm#P60_717 (footnotes omitted).

[69] Alexander also argues that time-sensitive pricing in regions with wholesale energy markets sends distorted price signals to consumers, because energy markets do not function properly. This argument goes to issues of welfare economics theory, rather than practicalities of customer costs and benefits. Whether energy markets succeed in identifying marginal costs of usage at any given time, they do identify prices that suppliers will offer at any given time (aside from the impact of contracts that lock consumers into a given price in the short-run). While consumer demand response to such prices arguably does not optimize welfare under economic welfare theory, it will lower bills for customers who can lower usage in the face of the actual, but "distorted" market-based prices. If persistent, the demand responses of some residential customers could lower bills for customers generally, to the extent that wholesale price reductions achieved through the demand response of some customers can be shared with all customers (and that, taken together with operational savings, such reductions are larger than the incremental cost of the AMI investment).

[70] This list (drawn largely from the recent testimony of Stephen S. George in the pending Central Maine Power Company alternative regulation case, which rebuts the prefiled testimony of Barbara Alexander in that docket) summarizes many of the counterarguments brought out by Alexander and other AMI opponents. To the arguments in his testimony, we add other

1. There is a large and growing body of evidence indicating that residential customers can and will respond to time-varying prices and, in particular, dynamic price signals such as critical peak pricing and peak time rebates.
    a. On average, residential customers will reduce energy use on critical days by an amount ranging from 11 to 25 percent in response to prices or incentives that are between four and six times higher than the average price they would have paid under a standard tariff.
2. The resulting decrease in energy use during high-cost periods can generate substantial savings to customers and to society as a whole.
    a. Market price benefits of demand reductions can be substantial, even with quite modest reductions in peak demand.
    b. Not every customer must reduce load in order for demand reductions to produce benefits for all customers. Roughly 80 percent of the total demand reduction for customers on the CPP tariff in California was provided by only about 30 percent of customers. The majority of customers on the pilot tariff reduced load by less than the average value while others reduced load much more.
    c. The benefits derived from high responders, whether in the form of lower market clearing prices or avoided investment in generation, would accrue to all customers, not just those that reduce demand. That is, customers who volunteer for time-varying tariffs and reduce demand on high cost days provide positive economic benefits to all customers.
3. Opponents present no evidence in support of their claim that customers don't like and might be harmed by price volatility.
    a. Customers find dynamic rate options not only to be manageable, but preferable to more static TOU options.
    b. Studies also show that, once customers experience time-varying rates, many prefer them over standard tariffs.
    c. The claim that customers don't like and might be harmed by price volatility is largely irrelevant, as most time-varying prices are not volatile. They simply offer prices that vary over time.
4. Pilot results indicate that the reduction in peak period energy use is similar across a variety of dynamic rate options.
    a. Customers respond similarly to price increases (e.g., a CPP tariff) as they do to incentives paid for peak-period reductions (e.g., a peak time rebate program).
    b. Consumers are likely to respond to the carrot-only incentive of a Peak-Time Rebate in a manner similar to a Critical Peak Pricing rate.
    c. Many more customers are likely to take advantage of this no-risk PTR option than would volunteer for a CPP tariff because of the fear customers have about increased bills under a CPP rate.

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arguments made by George and other proponents of AMI in published materials and email correspondence via the EEI AMI listserv.

5. Low-income customers can and do respond to time-varying price signals, without risk to health and safety.
    a. Low-income customers participating in the California SPP pilot were less price responsive than higher-income participants, but on average (other than those on the low-income discount rate, who did not shift load in statistically significant amounts) they reduced their demands 11 percent.
    b. A substantial number of low-income households are high-use customers, and a substantial portion of high-income households are low-use customers.
    c. Across income levels, mean bill change values were statistically indistinguishable.
    d. Low-usage customers save proportionally more than do high-use customers.
    e. Low-income customers did not pay more under CPP tariffs.
    f. Lower-income households participating in the Chicago real-time pricing pilot were more likely than non-low-income customers to be high responders.
    g. There is no evidence that low-income and elderly customers may suffer dire health and safety consequences as a result of "doing without" in the middle of a heat wave in order to avoid higher bills.
    h. Even if such claims are true, they are not applicable to a peak time rebate program, where bills do not increase in the absence of a change in energy use, but could fall if a consumer adjusts his or her energy use.
    i. Even if a CPP tariff were implemented (on a voluntary basis), customers typically find that the kinds of changes that are sufficient to reduce demand during high priced periods can be achieved based on behavioral changes that, at worst, impose relatively minor inconveniences.
6. It is possible to adapt the results of the CA SPP to other service areas with different mixes of climate and end-uses.
7. Direct load control (DLC) programs are not superior to time-varying prices made possible by AMI.
    a. Customers on time-varying prices experience no greater discomfort from usage adjustments in response to high prices than customers whose load is adjusted by the utility under a DLC program.
    b. DLC is not suitable for all utilities, especially those with low penetration of central air conditioning.
    c. A focus on load control ignores the flexibility and range of behavioral adjustments that can result from a peak time rebate or critical peak pricing program.
    d. In response to a price signal, consumers can choose to adjust their thermostat, turn off a light, shift a load of wash from the peak to off-peak period, or make any number of other changes in order to reduce their energy bills. This flexibility is one of the primary values of a pricing option compared with the more "command-and-control" approach associated with load control.
    e. Air conditioner load control does not support retail customer choice, unlike AMI. Providing customer choice and customer control not only improves customer response, frequently by over 100 percent, it also substantially reduces program costs (uses performance rather than participation payments) and improves customer satisfaction.

f. Finally, price-based incentives create performance incentives, in contrast to the participation payments (unrelated to performance) in the vast majority of direct control programs. Changing from participation to performance incentives also eliminates all free riders. In other words, price is more effective and more equitable.

This report will not attempt to analyze all the competing claims made by AMI critics and proponents. Rather, we will focus on whether residential customers as a group, and subsets of residential customers, can and do respond to time-varying pricing. We will also look at the bill implications of using AMI as a tool to support the offer of time-varying rates.

To explore what is known about the response of residential customers, and particularly low-use, low-income customers, to time-sensitive pricing options made possible through AMI investments, we turn to a description of three recent dynamic pricing pilots. After describing the pilots, we will take up the key questions raised by the critics' arguments, to glean what information is possible from the pilot results concerning the suggested problems of AMI and time-sensitive pricing.

B. Description of three pilot demand-response pricing programs

To understand how the three pilots might help predict the effect of similar dynamic pricing initiatives in other states, we start with a description of the populations receiving the pilot prices, the nature of the pilot prices, the timing of the pilot, the circumstances of any peak or critical peak pricing, and other variables of note. These facts provide a foundation on which the reader can consider whether the circumstances of any given pilot make them applicable elsewhere. In Section G, we will describe the results obtained from these pilots, as well as some results from two other studies.

1. California Smart Pricing Pilot (SPP)

In response to the crisis in electricity pricing and availability in 2000-2001, California policy makers undertook a number of initiatives to head off repetitions of that experience. Among these was the California Statewide Pricing Pilot (CA SPP). The CA SPP experiment was designed to explore the effects of a variety of pricing options on customer load shapes and associated system costs.[71]

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[71] Karen Herter, Patrick McAuliffe and Arthur Rosenfeld, "An exploratory analysis of California residential customer response to critical peak pricing of electricity," *Energy*, 32 (2007):25-34 (*Exploratory Analysis*), available at www.elsevier.com/locate/energy, at 26. The final report on the pilot, prepared by Charles River Associates, states that the pilot concluded in December 2004. Charles River Associates, *Impact Evaluation of the California Statewide Pricing Pilot (CRR CA SPP Final Report)*, March 16, 2005, at 4, available at: http://www.energy.ca.gov/demandresponse/documents/index.html#group3.

The California utilities tested the following three pricing options:

Figure XII: Pricing Options Tested in the CA SPP

1. A traditional TOU rate.
2. Two forms of Critical Peak Pricing:
    a. Participants assigned to the so-called Critical Peak – Fixed (CPP-F) tariff paid the critical peak price for a fixed number of hours on the days when the utility called a critical peak event, and a TOU rate otherwise. The utility notified such participants the day ahead of a critical peak event.
    b. Participants assigned to the so-called Critical Peak - Variable (CPP-V) tariff paid critical peak prices during a critical peak of varying lengths, between 2 and 5 hours, on the days when the utility called a critical peak event, and a TOU rate otherwise. The utility notified CPP-V customers the morning of a critical peak event.[72]

The pilot operators selected applicants for participation in the CPP-F group, to include a representative sample of customers statewide from within each stratum of usage and each of the four climate zones in California. They further selected subjects to ensure that the pool of participants fairly represented the dwelling types (apartment, single family) of customers in such usage and climate zones, and across the state.[73]

Program operators selected two groups of CPP-V customers. San Diego Gas & Electric (SDG&E) selected Track C participants from among customers participating in an ongoing smart thermostat[74] direct load-control program in the SDG&E service territory. Track A CPP-V participants were selected from SDG&E customers who were not on the direct load-control pilot, and who were high-use (>600 kWh/month) customers, residing in single-family homes with central air conditioning. Track A customers were offered a free programmable communicating thermostat (PCT).

The utilities selected control groups from among their customers. The control group members remained on the tariffs under which they had been taking service before the pilot. Utilities each selected the control group members to have roughly the same characteristics as the participants, in terms of stratum of usage, climate zone, and dwelling type.

[72] *Quantifying Demand Response,* at 54.

[73] *Exploratory Analysis*, at 2.

[74] A smart, or "programmable communicating thermostat" (PCT), is one that can be programmed by the customer or on the customer's behalf to adjust the temperature setting by time of day, day of the week, and in response to signals sent from the utility.

Each pilot rate was designed to be revenue-neutral. The TOU rate had an off-peak price lower than the average price for the standard rate, offsetting the price increase for on-peak periods. During the critical peak events, customers with a CPP form of rate saw much higher prices than during ordinary on-peak periods.

The underlying TOU peak price was 2 to 3 times the off-peak rate, depending on the utility. TOU peak prices were approximately 70 percent higher than the standard flat rate.[75] CPP-F and CPP-V prices on average across all utilities were about 10 cents/kWh in off-peak hours, 20 cents/kWh in peak periods, and 60 cents/kWh during critical peak hours.[76] The critical-peak price for CPP customers was between 5 and 10 times the off-peak price for the CPP rates, depending on the utility.[77]

Under the pilot the utility could call a critical peak event for up to 15 "critical" days of the year. The ordinary peak period for all residential tariffs ran from 2 pm to 7 pm on weekdays. The TOU peak periods were from 2 p.m. to 7 p.m.[78] The critical peak periods for participants on the CPP-F rate were also from 2 p.m. to 7 p.m., on critical event days. Thus, for CPP-F customers, the critical peak period during any given critical peak day was fixed at the 5 hours between 2 and 7 p.m. By contrast, the utility could define the critical peak period for the CPP-V customers between 2 hours and 5 hours, during the 2 p.m. to 7 p.m. period on critical peak event days.

The utilities notified CPP-F customers the day ahead of a critical peak event. They could notify CPP-V no later than the day of the critical peak event. The utility also signaled the PCTs of those customers with such devices at the beginning of the critical peak period. [79]

The utility could call up to 15 critical-peak events during the year (12 during the summer, and 3 during the winter).[80] Between July 1, 2003 and September 30, 2004, program managers called 27 critical peak periods.[81]

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[75] *Quantifying Customer Response*.

[76] *Exploratory Analysis*, at 27: "The average electricity price for the average non-participating California customer was about 13 cents/kWh."

[77] *Quantifying Customer Response*.

[78] Karen Herter, "Residential Implementation of critical-peak pricing of electricity," *Energy Policy* 35, at 2129.

[79] *Ibid.*

[80] *Exploratory Analysis*, at 27.

[81] *Ibid.*

2. Illinois: ComEd/Community Energy Cooperative - Energy-Smart Pricing Plan℠

The Community Energy Cooperative (Cooperative or CNT)[82] fielded its Energy-Smart Pricing Plan℠ (ESPP)[83] in greater Chicago, Illinois from 2003 to 2006.[84] Under the pilot, Cooperative members could enroll in the pilot, and the Cooperative randomly assigned ESPP enrollees to one of two groups: participants (651 members), who took service under dynamic rates; and a control group (103 members), who did not receive any of the ESPP educational information, and continued to pay a flat rate for their electricity.

The area utility, Commonwealth Edison (ComEd) installed interval meters at the homes of participating Cooperative members. ComEd priced participants' electricity usage based on anticipated hourly changes in the market cost of the commodity. The Cooperative assisted in the administration of the tariff. CNT notified participants a day in advance of the prices that would likely apply the following day, so they could better adjust their usage.

CNT through 2004 also offered smart thermostats to participants, which allowed them to pre-program changes in electricity use (primarily air conditioning) based on price levels picked in advance. During 2004 and continuing into 2005, CNT installed cycling switches on the central air conditioners of 57 participants. These switches were set to cycle the air conditioner 50 percent of the time during a high-price period.

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[82] The Community Energy Cooperative Energy is a non-profit organization helping consumers and communities obtain the information and services they need to control energy costs. The Cooperative created CNT Energy in January 2000 as a division of its Center for Neighborhood Technology:

> CNT Energy works to help its more than 8,000 members obtain the information and services they need to control energy costs. The organization's members include individuals and small businesses in northern Illinois. Members receive up-to-date energy information in newsletters and on the Internet. They also have opportunities to participate in pilot programs designed to benefit consumers and promote energy efficiency. In addition, members become part of a collective voice advocating for energy policies that benefit everyone.

http://www.cntenergy.org/our_members.php.

[83] Unless otherwise noted, the information for this description of the Energy-Smart Pricing Plan℠ is taken from the evaluations of the pilot conducted by Summit Blue Consulting, and available at: http://www.cntenergy.org/how-it-works.php.

[84] ComEd replace the in 2007 with a voluntary real-time pricing tariff available to all Commonwealth Edison customers. Ameren, another utility, also has offered a voluntary dynamic pricing tariff to its Illinois customers.

The Illinois Department of Commerce and Economic Opportunity (DCEO) provided the funding for the interval meters, programmable thermostats, and the evaluation reports on the pilot.[85]

3. Ontario Smart Price pilot

In 2006, the Ontario Energy Board (the Board) initiated the Ontario Energy Board Smart Price Pilot (OSPP) to test the reactions of and effects on residential consumer behavior of three different time-sensitive price structures:[86]

1. Time-of-use (TOU) prices
2. TOU prices with a critical peak price
3. TOU prices with a critical peak rebate (CPR)[87]

Hydro Ottawa ran the pilot between August 1, 2006, and February 28, 2007. Originally, the Board intended to end the pilot on December 31, 2006, but the Board decided to extend the pilot period until February 28, 2007, to obtain data on response during the coldest winter months. The Board initiated pilots by other Ontario utilities to test other tariff structures and specific demand response technologies.[88]

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[85] After 2004, the pilot stopped offering free smart thermostats, for lack of funding. According to Rob Lieberman, then head of CNT and now a member of the Illinois Commerce Commission, the Cooperative designed the pilot using low-tech methods of communication with customers, such as phone calls and emails from CNT, because CNT did not have sufficient funding to pay for the installation of more sophisticated communications equipment. E-mail to the author, December 17, 2007.

[86] Unless otherwise indicated, this description of the pilot and its results is taken from the July 2007 *Ontario Energy Board Smart Price Pilot Final Report (OSPP Evaluation)*, prepared by IBM and eMeter for the Board.

[87] Under a critical peak rebate tariff, the customer pays the underlying TOU rate for service, and faces no critical peak price during critical peak events, but rather may receive a credit for usage reductions during critical peak events, relative to a defined baseline. Hydro Ottawa defined a participant's CPR baseline usage as that customer's average usage during the same hours of the day over the participant's last five, non-event weekdays, as adjusted to increase the baseline. Hydro Ottawa increased the average usage by 25% to obtain the baseline usage. The rebate was calculated as the kWh difference between the participant's baseline usage and actual usage on the critical peak day, multiplied by C30¢.

In the Ontario pilot there was no reduction in off-peak pricing to keep the CPR rate revenue-neutral. *See OSPP Evaluation*, at Section 2.4, p. 18. The evaluation does not make it clear why the utility chose this design for the CPR tariff.

[88] Further information on these pilots is available on the OEB's website, at www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_regulatedpriceplan_smartpricepilot.htm.

Hydro Ottawa selected customers for three treatment groups out of those who responded to a solicitation mailed to customers with interval meters in place. Hydro Ottawa also selected a control group of non-participants from those residential customers who had expressed interest in participating.

Participants paid their usual (bi-monthly) bill at non-TOU rates as if they were not on the pilot price. In addition, they received monthly Electricity Usage Statements, showing the electricity supply charges that would apply on their respective pilot price plans. Upon enrollment, participants received a refrigerator magnet showing the TOU prices, periods, and seasons for the participant's price plan. They also received an electricity conservation brochure. Participants did not receive smart thermostats, although they could buy and install them on their own if they wished. The pilot did not include a direct load control component.

Neither participants nor the utility incurred incremental cost for the interval metering, since the utility had already installed meters in homes of customers eligible to participate, and was already recovering costs of the meter installations and related back office investments through adders to the customer charges applied to all customers.[89]

During the pilot, the utility billed all participants—TOU, CPP and CPR—for their usage at the TOU schedule in Hydro Ottawa's tariff. This TOU schedule had different prices for summer and winter, and for weekdays/non-holidays it had three pricing periods: off-peak, shoulder or mid-peak, and on-peak. TOU-only customers could save money if they backed off their usage during higher-priced periods, but there were no critical peak pricing periods for TOU-only customers.

Participants on the CPP rate were charged a separate, higher, rate for usage during the critical peak period. Customers on the CPR rate who used less than their baseline during critical peaks would pay the critical peak price (C30¢/kWh) during the critical peak period for usage, and receive a rebate equal to the CPP price times the difference between the "baseline" usage and their actual usage.[90] CPR customers earned a refund of C30¢ for every kilowatthour reduction below their baseline usage during the critical peak hours.

For critical peak price (CPP) participants, the Off-Peak price was reduced to C3.1¢/kWh, in order to offset the increase in the critical peak price and keep the overall effect of the rate

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[89] The government of Ontario had previously set a goal of universal installation of interval meters, and Hydro Ottawa was in process of fulfilling this mandate.

[90] Not all critical peak rebate tariffs follow this approach. For example, a utility could offer a customer the option to remain on the flat rate, and a Critical Peak Rebate for reductions relative to a baseline usage during Critical Peak periods. The differences in tariff design will create differences in the incentives to participate, and in the allocation of the benefits of the resulting demand response. The more that must be paid to the demand responder (in terms of rebates, in this case), the less of the resource savings will be available for sharing with other customers.

revenue neutral, relative to the pre-pilot usage. The CPP price was thus roughly 10 times as high as the off-peak price. The off-peak price for CPR customers was not reduced.

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 standard rates under which most residential customers took service (and which the participants paid during the pilot). The dollar effects of the TOU, TOU-CPP, and TOU-CPR pricing plans (relative to the ordinary residential rates) flowed through to participants through a settlement payment. The final settlement document compared their charges under the pilot tariff to what they would have been under the standard prices. The "thank-you" payment was the sum of $75 plus their pilot savings (or minus their pilot losses) relative to the standard tariff.

The utility declared critical peak days for CPR and CPP customers based on pre-determined temperature and Humidex[91] thresholds. Hydro Ottawa notified CPR and CPP participants of an upcoming critical peak day one day before the event, by telephone, email or text messages. The participants then had the choice of "buying through" the critical peak period[92] or else cutting back their usage during the critical peak period. According to the program design, critical peaks would last for only 3 or 4 hours on any give critical peak day. The maximum number of critical peak days allowed for the pilot was nine.[93]

Hydro Ottawa applied all price changes only to the commodity portion of a customer's electricity bill. Delivery, debt retirement,[94] and other charges were not changed in the pilot. None of the treatment or control participants took their commodity service from a non-utility provider.[95]

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[91] According to the Canadian Centre for Occupational Health and Safety, "Humidex is used as a measure of perceived heat that results from the combined effect of excessive humidity and high temperature." http://www.ccohs.ca/oshanswers/phys_agents/humidex.html

[92] "Buying through" is a term used in some voluntary demand response programs (i.e. without direct load control by the utility) for continuing to use, and pay for, energy at the rate the customer would have used in the absence of the higher peak (or in this case, critical peak) prices.

[93] During the pilot months, during which the weather turned out to be relatively moderate, only 7 critical peak events were declared: 2 in August 2006, 2 in September 2006, and 3 in January 2007.

[94] Canadian tariffs sometimes have line items to amortize specific debts.

[95] As in the U.S. jurisdictions with retail choice, the great majority of residential customers take their commodity service from their distribution utility, in this case Hydro Ottawa. These customers would likely be on a Standard Offer, Standard Service, Default, Basic Service or equivalent service for non-shopping customers in a retail competition jurisdiction in the United States.

C. Results of three demand-response pricing pilots

1. To what extent did residential customers on average reduce load in response to critical peak pricing and direct load control in the pilots?

All three pilots showed at least load shifts by residential customers on average[96] in response to critical peak price signals.[97] Average responses were typically more pronounced during weather extremes, particularly during hot weather, and among customers with relatively high-demand end uses, such as central air conditioning. Automatic responses, made possible by direct load control, programmable thermostats or other devices, contributed to significantly higher demand responses.

Some participants, however, in at least two of the pilots, increased their usage on average during some critical peak periods. Further, mean load reductions observed in any given period do not show that all customers in the pricing group did or were able to reduce load during the period in question. In at least one pilot group, the group average reductions were almost entirely the result of huge load reductions by a small number of participants. Evaluators of another pilot noted that not all participants reduced their loads, although the pilot group under study did reduce loads on average.

As with all discussions of demand response to pilot tariffs, we must remember that bill impacts, the factor of most concern to most customers (and many legislators), do not move in lock-step with demand responses. Bill impacts will be discussed in a separate section, below.

2. Summary of average residential demand responses

The following summary[98] shows overall average residential elasticity and impact results from the various pilots discussed above:

[96] This section will not discuss groups broken down by income or usage level, at least not directly. The findings with respect to such groups are discussed in a separate section, below.

[97] Response to ordinary TOU rates was less pronounced than response to critical peak pricing. We will focus our discussion on more higher pricing of narrowly focused critical peaks.

[98] Data extracted from Table 2, Keisling, *Prospects and Challenges*, p. 36; ESPP and Ontario load reduction data from Section III.B, above.

Figure XIII: Summary of Recent Pilot Demand Reduction Results

Pilot	Pricing Type	Year	Own-Price Elasticity	DLC or PCT?	Peak Consumption Reduction[99]
Ameren-UE	CPP	2005		n/a	9.3%-17.8% (ave. 13%)
Ameren-UE	CPP	2005		All	14.4%-30% (ave. 23.5%)
CA SPP	CPP-F	2003	-0.035	some	n/a
CA SPP	CPP-F	2004		some	13% (average)
CA SPP	CPP-V	2003-4	-0.027 to -0.044	all	27% (average)
CNT ESPP	CPP-F, CPR	2003	-0.42	no	As much as 23%
CNT ESPP	"	2004	-0.08	some	
CNT ESPP	"	2005	-0.47	some	
CNT ESPP	"	2005	-0.69	all	
CNT ESPP		2003-5			As much as 15%-20%
Ontario	CPP	2006		some	25.4% (summer CP hrs)
Ontario	CPP	2006-7			No response, or increase
Ontario	CPR	2006			17.5% (summer CP hrs)
Gulf Power	CPP	2001			22% (high price signal)
Gulf Power	CPP	2001		all	Max. 41% (CP event)
GridWise™	RTP	2006-7			15-17% (average)

The results of several pilots, then, show that residential customers, *on average,* have responded strongly to various types of dynamic pricing. Critical peak pricing, in particular, has shown promise as a demand response tool for residential customers.[100] The addition of programmable communicating thermostats significantly increases the responses observed.

a. California

A number of analysts have reviewed the data from the CA SPP. Their evaluations suggest that on average, most types of customers will reduce their critical peak loads in response to critical peak pricing. Technology such as smart thermostats boosted this response noticeably.

[99] The chart gives averages for the participant groups, unless otherwise noted.

[100] This report does not focus on time-of-use rates, as such rates did not call forth the strongest responses in any of the pilots.

In evaluating the California pilot, Herter *et al.* compared the participants' loads over all critical peak hours to their average loads on non-critical weekday peaks."[101] Herter *et al.* found statistically significant load reduction for participants on average, both with and without automated end-use control technologies.[102]

On average, according to Herter *et al.*, during 5-hour critical peak periods, participants without control technology (so-called "manual" participants) used 4 percent to 13 percent less energy than they did during normal day peak periods, depending on the temperature during the day. Herter *et al* estimated that "manual" participants reduced load across all the critical peak hours by 0.23 kW on average, relative to their average loads across all non-critical weekday peak periods.[103] During critical peak days with mild temperatures, the researchers observed average load reductions for the manual group of 4 percent compared to normal day loads.[104] As a percent of normal (non-critical peak) day loads, their response was greatest on the hot days—on average, "manual" participants' critical peak load on hot days was 13 percent lower than their non-CPP day load.[105]

Not all customers (or groups of customers) will reduce their loads in response to higher peak prices. Indeed, customers may actually increase peak loads in any given peak period, despite the higher unit price they will pay for such usage. In California, for example, in one mild-temperature period, the manual group actually *increased* load by 8 percent on average during a critical peak period. Finally, for manual group participants on cold days, load fell on average 9 percent below the corresponding load on normal days.[106]

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[101] *Ibid*., at 29. "Since participants are on TOU rates on normal days, the demand response estimates are the incremental impacts of CPP events beyond the impacts of the TOU pricing."

[102] Herter *et al* divided critical peak pricing participants into two main groups for the purpose of impact analysis: (a) a "PCT" group, whose members had installed programmable communicating thermostats connected to their central air conditioning units and other high-load end uses—the CPP-V customers; and (b) a "manual" group, whose members did not have such response technologies—the CPP-F customers.

[103] *Ibid*.

[104] *Ibid*. This effect was considered load shifting, given an increase in energy use over the entire day.

[105] *Ibid.* The researchers opine, based on comparisons of energy usage, that the CPP vs. normal load differential represents conservation at critical peak hours, rather than simply load shifting.

[106] *Ibid.* Average consumption (total energy use) on these cold days increased 1 percent, due to increased loads in the morning hours before the critical event.

Figure XIV: CA SPP - Average Response of Customers without Programmable Communicating Thermostats, by Temperature Band

Source: Herter, *et al*, Tables 2, 3[107]		
Temperature Band	**% Load Change**	
50 – 54.9	-11	-9
55 – 59.9	-7	
60 – 64.9	***8***	-4
65 – 69.9	-7	
70 - 74.9	-2	
75 – 79.9	-6	
80 – 84.9	-6	
85 – 89.9	-7	
90 – 94.9	-4	
95 – 99.9	-15	-13
100 – 104.9	-12	

Note that when Herter *et al* consolidated the eleven original temperature bands into three, both manual and CPP-V groups showed load reductions in response to critical peak events in all three temperature bands. The 8 percent increase shown in the cool temperature band of 60 to 65 degrees is folded into the reductions in the other temperature bands between 60 to 95 degrees.

Smart thermostats, a technological assist to customers seeking to adjust usage in response to price, boosted demand responses considerably. Those participants with these programmable communicating thermostats (the "PCT" group) used 25 percent less on average over the hottest 5-hour critical peak periods than they did on normal day (TOU) peak periods. Participants with central A/C and programmable thermostats, on the CPP-V rate, achieved an average reduction of 41 percent during one of the 2-hour critical peaks:

[107] Negative number indicates demand reduction in critical peak hours; positive number indicates demand increase in critical peak hours. This convention is maintained for consistency with the presentation of results for the other pilots. Note that the OSPP evaluation reversed the signs.

Figure XV: CA SPP - Percent Demand Response, Participants with PCTs, by Temperature Band and Length of Critical Peak

Source: Herter *et al*, Table 4		
Temperature Band	**PCT – 5 hours**	**PCT – 2 hours**
70 - 74.9	-8	-14
75 – 79.9	-1	-13
80 – 84.9	-6	-16
85 – 89.9	-7	-17
90 – 94.9	-25	-41

Thus, during the CA SPP study period, the average residential customer load responses during critical peak pricing periods ranged from a drop of 1 percent to a drop of 41 percent, depending on the temperature band at the time of the critical peak event.

The highest responses occurred on the hottest days, whether or not the participants had to reduce load manually or could use smart thermostats programmed in advance to respond to price signals by lowering loads in the house. On these high-temperature days, the manual group (less than 50 percent air conditioner penetration) on average reduced load 13 percent, and the group with programmable communicating thermostats (100 percent air conditioning penetration) reduced load on average 25 percent. Among those with air conditioning, on average they reduced load by 17.4 percent, compared to the 25 percent drop achieved by those with PCTs (see CA SPP Final Report, Table 4-19).

The Herter *et al* results are largely consistent with the effects estimated by Charles River Associates, broken out by climate zones rather than by the temperature band of the critical peak days:

Figure XVI: Percent Changes in Demand, Peak Period of CPP Days, by Climate Zone, TOU, and CPP-F Groups

Climate Zone / Tariff	Cool Zone	Mild Zone	Hot Zone	Very Hot Zone	Statewide
CPP - F	-11%	-11%	-16%	-16%	-12%

Source: *Impact Study*, Figure 3.

As can be seen from the following table, customers on the CPP-F pilot rate reduced their peak period usage considerably more during critical peak events than during normal peak periods, in each climate zone.

Figure XVII: CA SPP - Percent Change in Peak Period Energy Use by Climate Zone, CPP-F Participants

Source: CRA CA SPP Final Report, Executive Summary		
Climate Zone	Normal Peaks	Critical Peaks
Zone 1	-2.2%	-7.6%
Zone 2	-3.3%	-10.1%
Zone 3	-5.6%	-14.3%
Zone 4	-6.5%	-15.8%
Statewide	-4.8%	-13.1%

CRA reported that participants on the CPP-V tariff in Track C (subject to critical peaks of varying lengths, with "day-of" notice of critical peak events, and already participants in the SDG&E demand-response program) showed strong responses (an average reduction of 27.23 percent) to utility calls of critical peak events. Participants on the CPP-V tariff in Track A (SDG&E single-family households with central air conditioning, offered smart thermostats, not previously on the demand-response program) responded less intensely, reducing demand during critical peak events on average by a little over 15 percent.

Based on data reported by the California Energy Commission, CPP-F participants reduced load during critical peak days on average. The CPP-F customer load reduction was most pronounced during hot and very hot weather peaks. On average during cool-weather critical peaks, CPP-F customers slightly increased their usage.[108]

b. Illinois: ESPP

Summit Blue Consulting prepared an impact evaluation of the Illinois ESPP for each of the pilot's three years. The analysts presented most results in terms of price elasticity: the percentage by which participants changed their usage in response to a percent increase in price during the critical peak period. This approach makes it difficult to compare results to those of other pilots, where the data is primarily presented in terms of reduction of peak consumption, without connecting that peak reduction to the price increase. However, there are some data available about percentage load reductions in the ESPP evaluations, and there are data available regarding price elasticities estimated for participants in the other pilots discussed here.

Over the course of the pilot, Critical Peak/Real Time pricing participants on average reduced their peak usage between 15 percent and 20 percent.[109] Participants with switches on their central air conditioning units allowing programmed cycling off during high-price periods

[108] Pat McAuliffe and Arthur Rosenfeld. *Response of Residential Customers to Critical Peak Pricing and Time-of-Use Rates During the Summer of 2003* (CEC Residential Report), California Energy Commission, September 23, 2004, Figure 4.

[109] Posting by Steven George to EEI's AMI Listserv, citing a recent presentation by Anthony Starr, in response to author's questions, December 5, 2007.

showed stronger demand responses on average than other participants. For example, on the hottest days of the summer of 2004, at the highest peaks of the day, those with air conditioning cycling switches reduced loads on average about 23 percent, whereas participants as a whole reduced load by 15 percent.[110]

The evaluators estimated the key results from the impact evaluation of the 2003 ESPP program using data from August, the month in which the system tends to peak in ComEd's service area. That peak month in 2003 was substantially cooler than normal; as a result, peak-period prices were lower than in previous years.[111] From the 2003 data, the evaluators drew the following conclusions:

1. Over half of all participants showed noticeable responses to price notifications.
2. Most of the rest of the participants showed some response.
3. Some of the participants showed no response.
4. On average, participants did respond to hourly prices. Residential customers responded to hourly prices (over and above the "high price" notification) with an average price elasticity of -4.2 percent.[112]
5. Participants responded strongly to advance notification of high prices (prices over 10 cents/kWh); consumption decreased in some cases by more than 25 percent in the first hour. This response tapered off both (1) over the length of the high price period, and (2) as the number of successive days of notifications increase.[113]

According to the then-head of the Cooperative running the pilot, results of the pilot in 2003 demonstrated significant participant response to high price notifications, up to as much as 23 percent of peak demand,[114] when compared to usage on a similar day without high prices.

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[110] Bob Lieberman, member of the Illinois Commerce Commission, presentation: *Demand-side Resources in a Restructured State: Possibility or Non-Sequitur*, Presentation to Annual MARC Conference, June 18, 2007. Available at: http://www.puc.state.mn.us/news_events/events/marc_07/speakers/lieberman.pdf.

[111] The evaluators suggested that these results might not be representative of responses during peak months whose weather and associated usage requirements are more representative of normal peak months.

[112] For every 1 percent increase in the price of electricity for a given hour, participants reduced load by 4.2 percent on average.

[113] The Hydro Ottawa pilot evaluators referred to this effect as "decay" of the demand response.

[114] Lieberman, *Demand-Side Resources in a Restructured State*.

In the second summer, the Chicago area weather was milder than in the first summer of the ESPP pilot.[115] Accordingly, in 2004 there were only 19 hours, spread over seven days, when prices were over $0.10/kWh (so-called "high-price" days). Peak-period prices were correspondingly lower than during previous years. Electricity use for air conditioning was also lower than normal. The evaluators reported the following results, among others:

1. In 2004, participants did not respond strongly to notification of high prices (prices over $0.10 per kWh).
2. Residential customers in 2004 had an average overall price elasticity of -8.0 percent (compared to a -4.2 percent response in 2003).

Summit Blue noted that the summer of 2004 was unusually cool, and so "not particularly taxing of participants' good will and energy saving efforts." For this reason, these results were "not surprising." Summit Blue opined that the results were due to the limited use of air conditioning during non-high priced periods (the baseline usage was small), and to sparing use of air conditioners during the few high temperature days (which were also high price days).

In 2004 it was not possible to confirm the effect of high price notifications. The lack of comparison days in summer 2004, and the relatively low use of air conditioning on even the hottest days of that summer, precluded a similar analysis for the second year of the pilot.

Cooperative-controlled direct load control devices, added to some participants' air conditioners in 2004, did not produce statistically different results for such participants in that summer. Summit Blue attributed this outcome to the relatively low amount of air conditioning used on even the hottest summer days of 2004.

The weather in the Chicago area was dramatically hotter in the third year of the pilot.[116] In the summer of 2005, the ComEd system experienced record peak electricity demands. In addition, the prices for natural gas (an input to the production of electricity) that summer exceeded prior summer's levels, contributing to higher electricity prices. These market conditions resulted in high hourly electricity prices throughout the summer.

Summit Blue reported the following notable effects from the 2005 evaluation (among others):

1. ESPP participants continued to respond to hourly electricity prices in a manner similar to prior years, with an overall price elasticity of -4.7 percent.

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[115] It was the fourth coolest summer in the previous twenty-five years. Summit Blue acknowledged that these weather patterns did not provide the ideal environment for testing a typical range of peak prices and usage patterns.

[116] June and July of 2005 were the sixth warmest of all comparable months on record since 1871.

2. Participants in 2005 showed a substantial response to the high-price notifications (i.e., when prices exceed $0.10/kWh).
3. Automatic cycling of the central-air conditioners (turning the compressor on and off for short periods of time via remote control) during high-price periods added as much as 2.2 percent to a participant's price elasticity, for a total price elasticity of 6.9 percent during such periods.
4. Customers' responses to high-price notifications declined somewhat as the number of consecutive notification days during the summer increased and as the length of a given high-price period increased (snapback effect). Summit Blue also identified what it calls a "recharge" effect, as customers' response recovered to initial levels the longer the number of days between high-price notifications.

c. Ontario Smart Price Pilot

OSPP outcomes were measured by comparing the electricity consumption behavior of customers receiving the experimental prices (TOU, CPP, and CPR, respectively) to the consumption behavior of the control group: customers remaining on their existing two-tier non-TOU rates. For all three price groups combined, participants responded with statistically significant[117] shift in load away from peak periods during on-peak periods on the 2 critical peak days called in August 2006. No statistically significant shift was detected during the critical peak days declared in September. In January 2007, CPP participants actually increased their load on one critical peak day, and displayed no statistically significant change in load on the other two critical peak days:

Figure XVIII: Ontario SPP Results: CPP Pricing

Summer			
Critical Peak Day	**Load Reduction**	**Actual Max Temp (Celsius)**	**Humidex**
Friday, August 18	-27.7%	30	35
Tuesday, August 29	-10.1%	25.2	28
Thursday, September 7	n/s[118]	22.4	n/a
Friday, September 8	n/s	26.5	31

Winter		
Critical Peak Day	**Load Reduction**	**Actual Min. Temp. (Celsius)**
Tuesday, January 16	n/s	-18.7

117 At the 90 percent confidence level. The evaluators note that many of the load shift results are statistically significant at the 95 percent and even 99 percent confidence level.

118 The term "n/s" denotes that the results were not statistically significant.

Wednesday, January 17	**7.2%**	-16.1
Friday, January 26	n/s	-21.3

The load reduced during critical peak hours across all four summertime critical peak days was 17.55 for CPR participants and 25.4 percent in the case of CPP participants[119]. CPP participant demand reduction across the entire summertime peak period (11am to 5pm) during the same critical peak days was not as great as it was across the specified critical peak hours. During this narrower set of hours, CPP participants reduced demand in amounts ranging from 2.4 percent to 11.9 percent.

Analysts examined load shifting away from the on-peak period for all days in the pilot, not just critical peak days. Evaluators found no statistically significant load shifting from on-peak periods as a result of the TOU price structure alone.

d. Other program results

Summary results available for two other dynamic-pricing pilots are consistent with the results of the three pilots examined in detail here.[120]

In 2001, Gulf Power, a Florida subsidiary of Southern Company, commissioned an evaluation of its residential demand response program, Good Cents Select. This program is based on a combination of metering and control technology, customer service, and a four-part TOU pricing structure. Good Cents Select customers all have a programmable thermostat that allows them to establish settings based on temperature and price. Each Good Cents Select home has a programmable gateway/interface that enables the customer to program up to four devices in the home to respond to price signals. Gulf Power has installed meter-reading technology and load control technology that enables customers to program load shifts in response to price

[119] Time of use participants showed lower responses than either CPP or CPR customers.

[120] The material on Gulf Power and the Olympic Peninsula evaluations is drawn from the discussion by Kiesling, *Prospects and Challenges*, pp. 26-27, which in turn references Severin Borenstein, Michael Jaske and Arthur Rosenfeld, *Dynamic Pricing, Advanced Metering and Demand Response*, University of California, Center for the Study of Energy Markets, Paper No. CSEMWP 105 (2002). http://repositories.cdlib.org/cgi/viewcontent.cgi?article=1005&context=ucei/csem and Government Accountability Office, *Electricity Markets: Consumers Could Benefit From Demand Programs, But Challenges Remain*, GAO-04-844, August 2004, available at *http://www.gao.gov/new.items/d04844.pdf*. Recently, the Pacific Northwest National Laboratory issued its reports on the Pacific Northwest GridWise™ Demonstration Project (which included the Olympic Peninsula Project and the Grid Friendly™ Appliance Project). These reports, and an overview, are available at: http://gridwise.pnl.gov/docs/op_project_final_report_pnnl17167.pdf, http://gridwise.pnl.gov/docs/gfa_project_final_report_pnnl17079.pdf, and http://gridwise.pnl.gov/docs/pnnl_gridwiseoverview.pdf.

signals. Customers also pay a monthly participation fee of $4.53 (said to cover approximately 60 percent of program costs to the utility).

In 2001, Gulf Power customers on average reduced energy usage 22 percent during high-price periods and 41 percent during critical periods. The Gulf Power evaluator reported that customer satisfaction is 96 percent, despite the monthly participation fee.[121]

The Olympic Peninsula GridWise® Testbed Project was a demonstration project run by the Pacific Northwest National Laboratory (PNNL) and local utilities, funded by a grant from the United States Department of Energy, with additional contributions from appliance and load control equipment manufacturers. PNNL tested a residential network with highly distributed intelligence and market-based dynamic pricing. The pilot lasted from April 2006 through March 2007. PNNL and the utilities enrolled 130 households who heated with electricity. Each household received a PCT with a visual user interface that allowed the consumer to program the thermostat in response to price signals, if desired. Households also received water heaters equipped with a GridFriendly™ appliance controller chip that enables the water heater to receive price signals and to be programmed to respond automatically to those price signals. Consumers could control the sensitivity of the water heater through the PCT settings.

Participants continued to purchase energy from their local utility at a fixed, discounted price. In addition, they received a cash account with a pre-determined balance, which the utility replenished quarterly. The participants' energy use decisions would determine their overall bill. The billed amount was deducted from their cash account; participants kept any residual as profit. The worst a household could do was a zero balance. Participants could log in to a secure web site to see their current balance and how effective their energy use strategies were.

The participating households received extensive information and education about the technologies available to them and energy use strategies made possible by these technologies. They were asked to choose a retail pricing contract from three options: (a) a fixed price contract (with an embedded price risk premium), (b) a TOU contract with a variable CPP component that could be called by the utility in periods of tight capacity, or (c) a RTP contract that would reflect a wholesale market-clearing price in 5-minute intervals.[122] The project managers controlled the thermostats of the RTP households.[123]

The price offered for demand reductions varied according to the constraints on the feeder serving the peninsula. The project limited the feeder capacity to test the usefulness of demand response and distributed generation options for relieving feeder constraints. During times of

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[121] Borenstein, et. al. (2002), Appendix B.

[122] The real time price was determined using a "uniform price double auction," in which buyers (households and commercial) submitted bids and sellers submitted offers simultaneously.

[123] All households could override project control of their loads. Pacific Northwest GridWise™ Testbed Demonstration Projects, Part I: Olympic Peninsula Project, Final Report (PNNL Final Report), October 2007, p.vii.

severe constraint, the effect on the cost of utility resources available to the peninsula drove up the price offered for demand response.

The households ranked the contracts offered, and the utility then placed them into three fairly even groups of participants receiving one of the pilot rate types, and one control group.[124] All households received either their first or second choice of pilot type.

A preliminary analysis of data from the first nine months of the program showed that peak consumption on average for the RTP group decreased by 15 to 17 percent, even though overall energy consumption increased by approximately 4 percent.[125] In the Final Report, PNNL estimated that RTP customer load was reduced by 5 percent during the baseline level of feeder constraint (and associated real time prices), and by 20 percent during periods of severe feeder constraint, and associated market prices.[126]

In 2005, Ameren-UE, a Missouri utility fielded a pilot testing a three-tier TOU rate, as well as the TOU rate with a CPP feature and the same rate with CPP and smart thermostats. The pilot was targeted at high summer usage residential customers. The CPP group without thermostats reduced load between 9.3 percent and 17.8 percent over the critical peak event days, with a reduction of 13 percent averaged over all eight critical peak days. Those with CPP pricing plus a smart thermostat showed a range of reductions between 14.4 percent and 30 percent, depending on the critical peak day, and averaged a 23.5 percent reduction over all eight critical peak days.[127]

3. To what extent were the participants in the three pilots representative of residential customers, including particular subsets of such customers?

Anyone considering econometric or sociological data must be conscious of whether the participants in the experiment (here, the pilots) were representative of the population at large. If the subjects of the pilot were not representative of the population as a whole, then the results of the pilot are potentially "biased."

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[124] The members of the control group received the enabling technologies and had their energy use monitored, but they did not participate in the dynamic pricing market experiment.

[125] Keisling notes that the price elasticity results for the RTP group are highly specification-dependent: the sign, magnitude, and statistical significance of the elasticity estimate varies greatly depending on arithmetic model specified to estimate the relationship between independent variables and the dependent variable (here, percent change in usage). Regulators need to be on the lookout for this phenomenon, which is not unique to the Olympic Peninsula pilot.

[126] PNNL Final Report, at x.

[127] Rick Voytas, "Ameren UE Critical Peak Pricing Pilot," presentation June 26, 2006.

There are a number of ways in which a sample can become biased.[128] A common issue for social science experiments is the so-called "self-selection" bias. That is, did the participants select themselves into the pilot, and were people with particular usages, incomes, housing types, attitudes, or other demand-influencing factors more likely to sign up to participate than other types of customers? Was the result a sample of households that does not represent the population whose behavior we are trying to predict?

To the extent the question is whether customers will "self-select" into a voluntary time-varying tariff option, the pilot designers did as well as might be expected in the circumstances to minimize experimental self-selection bias. Self-selection bias was a concern for all the pilot designers and evaluators. Absent the mandatory placement of a customer on a particular rate, any pilot will have to rely on decisions by customers to sign up for the pilot.[129] Pilot designers had to address the potential for self-selection by participants who were not representative of the target population of the tariffs being studied.

Unable to select participants at random from target populations, pilot managers in California and Ontario still took steps in an effort to obtain groups of participants that matched some of the key characteristics of interest in the greater population to which they belonged. In Ottawa, despite utility efforts to obtain a representative sample, evaluators determined that participants were more likely than non-participants to: (a) reside in detached single-family homes, (b) live in newer housing, (c) have central air conditioning, (d) have more education, and (e) have a higher income, than the population as a whole.[130]

In the California SPP, pilot administrators took pains to ensure that participants were representative of California electricity customers by climate zone, housing type, and low or high usage.[131] Evaluators also collected data on treatment group participants' pre-pilot usage, which they say allowed them to separate out the effects of factors other than the pilot rates (including self-selection bias) on their demand responses.[132] Herter *et al.* note, however, that they lacked

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[128] This statistics term is not meant to imply an intentional skewing of the data, but rather an objective description of a tendency in the data to bias the results.

[129] According to the CRA evaluation, California SPP pilot designers did seek a ruling from the California Commission placing customers in the various treatment groups, with the right to opt out, but the Commission declined to force customers into any of the pilot rates. CRA *SPP Final Report*, at 21. The Commission noted that California law required that participation in time-of-use pricing pilots be voluntary. California Public Utilities Code Section 393(c)(3), cited in the *Advanced Metering Final Decision*, Section IV(B) (Legislative Mandates), available at: http://docs.cpuc.ca.gov/published/final_decision/24435.htm#P60_717.

[130] *OSPP Evaluation*, Section 3.4. The Ontario pilot evaluators did not discuss self-selection bias in their report.

[131] Exploratory Analysis, at 27.

[132] CRA, *CA SPP Final Report*, at 5, and *CEC Impact Study* at 3-4. CEC used a "difference of differences" technique. From the CRA description, they used a similar technique.

the data to perform the statistical operations commonly used to reduce the possibility of self-selection bias in the results.[133]

Evaluators in some cases used statistical techniques to assess the pilot data, in an effort to overcome the possible impact of self-selection bias.[134] However, the characteristics they chose as predictors of participation, and thus used to correct for self-selection, did not include all the factors that one might reasonably surmise could distinguish a customer interested in and willing to participate from one who is not.

For example, the participation factors used in the ESPP analysis included (a) whether the household had recently acquired new appliances, (b) whether they used a fan to reduce costs, (c) the number of people in the household, (d) whether they lived in a single-family detached house, and (e) whether a respondent was 65 years of age or older.[135] These factors did not include such characteristics as ability to read and write,[136] a desire to help address social problems, or environmental consequences of energy use, an interest in having one's opinion taken into

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While this technique controls for difference in pre-treatment energy use, it does not necessarily eliminate all effects of self-selection into participation. McAuliffe and Rosenfeld note, for example, that this approach had limited usefulness given the small sample sizes and the large confidence intervals in the pre-treatment period. *CEC Impact Study,* at 14.

[133] *Exploratory Analysis,* at 32-33. Herter *et al* reference the seminal paper by later Nobel Prize winner James Heckman, "Sample Selection Bias as a Specification Error," *Econometrica*, Vol. 47, pp. 153-161 (1979). Tests following Heckman's method are commonly known as "Heckman" procedures. Heckman's insight has spawned a large literature on various ways to use participation factors and other statistical tools to try to correct for self-selection bias. The difficulties in the application of these methods can be appreciated by reference to the following articles, among many: Raymond S. Hartman, "A Monte Carlo Analysis of Alternate Estimators in Models Involving Selectivity," *Journal of Business & Economic Statistics*, Vol. 9, No. 1. (Jan. 1991): 41-49, available at http://links.jstor.org/sici?sici=0735-0015%28199101%299%3A1%3C41%3AAMCAOA%3E2.0.CO%3B2-G; and François Bourguignon, Martin Fournier, Marc Gurgand, *Selection Bias Corrections Based on the Multinomial Logit Model: Monte-Carlo Comparisons*, September 6, 2004.

[134] See, e.g., *ESPP 2003 Evaluation*, Section 2.1. The Mills Ratio described there is a step in the Heckman form of correction for self-selection bias. See, e.g., Dennis J. Aigner and Khalifa Ghali, "Self-Selection in the Residential Time-of-Use Pricing Experiments," *Journal of Applied Econometrics,* Vol. 4, Supplement: *Special Issue on Topics in Applied Econometrics*, December 1989, pp. S131-S144. Available on line at:http://links.jstor.org/sici?sici=0883-7252%28198912%294%3CS131%3ASITRET%3E2.0.CO%3B2-S.

[135] *Exploratory Analysis*, at 33.

[136] In California and in Ontario, the utility solicited participants by mail.

account, or a facility with filling out forms, handling new technologies, or mathematics, just to name a few.[137]

Each of the pilots suffered from the fact that participation was voluntary; that is, selected participants either had to come forward in response to a solicitation of interest in being part of an experiment. While at least in the case of the CA SPP a "wet signature" was a legal requirement imposed on the pilot program designers, the fact remains that as a result, customers identified for the pilot had to self-select into participation. Circumstances of the enrollment processes for the various pilots that differ from the circumstances of an ongoing tariff, yet may have affected decision of certain groups of otherwise-eligible customers not to apply (or conversely provided some customers an unrealistic incentive to apply for the pilot), include:

Figure XIX: Some Potential Sources of Self-Selection Bias in Pilots

- Cash incentives for participation (California and Ontario).[138]
- Requirement to join a cooperative membership organization with other aims and activities besides energy efficiency and demand response.
- Requirement that applicants be able to read and understand letters of solicitation sent by their utility (California and Ontario).
- Need to be reachable by the utility within the time frame of the pilot.[139]
- Interest in helping solve the state's energy problems (California).

Customers who would not have chosen such rates without cash incentives did not apply in the California and Ontario pilots (although, on the other hand, customers who would have chosen the pilot even without cash incentives did apply). If there are no such cash rewards when piloted rates are offered on a permanent (and voluntary, opt-in) basis, customers may not opt to take service under the rate.

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[137] Prospective participants in the SDG&E service area were told they would "have an important role in influencing how electricity is priced for millions of California customers in the future" and that they would be "contributing to a statewide research effort to help create a more secure energy future for California." At least at the beginning, prospective participants in the Chicago ESPP had to join the CNT cooperative; not all members of the population could or would go through such a step to achieve energy savings.

[138] A sizable number (20 percent or more) in all California treatment groups indicated that they joined primarily because of the promised $175 payment. Momentum Market Intelligence, *SPP End of Summer Survey Report (Draft*), January 21, 2004, p. 61. On an open-ended version of the question of why a participant entered the pilot, 15 percent to 33 percent of the respondents, depending on tariff type, included the $175 payment as a reason. *Ibid.*, at 60.

[139] Almost two-thirds of those solicited for participation in California were either unreachable after two attempts, or were otherwise excluded from participation. There is no information on the breakout of those who were unreachable, and the reasons for the inability of the utility to achieve contact with them.

There is no practical way to eliminate self-selection bias where a pilot is set up to test whether customers will voluntarily sign up for a particular tariff. In such a case, the regulator may be served by having expert statistical, econometric, or sociological advice when considering evidence such as the pilot evaluations discussed here.

If the regulator is testing mandatory or opt-out tariffs, self-selection does not present the same concerns, so long as the regulator (or legislature) permits the pilot designers to place customers on the pilot tariff without their consent. There are sound policy reasons to do so.

4. Did low-use or low-income customers respond to dynamic pricing?

Because low-income customers are at disproportionate risk of non-payment and disconnection,[140] analysts have paid special attention to the likely ability of such customers to take advantage of dynamic pricing. The chief argument regarding adverse impacts on low-income customers follows from the fact that such customers are disproportionately low-use customers. Thus, to the extent that low-use customers cannot lower their usage during critical peak periods, the argument goes, they will necessarily experience higher bills than if AMI and dynamic pricing were not in place. In addition, AMI opponents argue that low-income customers lack the funds to make their homes more efficient, as by buying appliances that draw less power.

Others argue that low-use customers enjoy better load shapes than other residential customers, and so will benefit from the reductions in off-peak pricing while not being exposed to substantial critical peak bills. One analyst in California, looking at the data for that state, observed that low-use customers indeed reduced demand by a smaller nominal amount of kW, but that as a percentage of their pre-existing load, their reductions were substantial.[141] As a result, according to this analyst, low-use customers enjoyed a higher percentage bill savings from the institution of time-varying pricing than higher use customers. As a corollary, to the extent that low usage is a marker for low-income, low-income customers would also enjoy such bill reductions.

As discussed below, however, the data on low-use responses to critical peaks, and low-income customer responses, do not paint a clear picture of reduced demand during peak periods.

[140] Ron Grosse, former manager of customer accounts for Wisconsin Public Service, estimated that approximately one-half of residential customers who did not pay their bills could not afford to pay them. Low-income customers represented considerably less than one-half of the residential customer base, however. See generally "Win-Win Alternatives for Credit and Collection," available at: www.citizensutilityalliance.org/energy/Win-Win.pdf.

[141] *Residential Implementation*, at 2122.

a. The responses of low-usage participants varied, even within the same pilot

The three pilots examined in this report provide varied evidence of the demand response of small usage customers to dynamic pricing. Depending on the definitions of low-use and low-income, different analysts reported different results even within the same pilot. [142]

With regard to the situation of low-use customers, TURN in California conducted an in-depth analysis of usage patterns among residential consumers in the State,[143] in support of its argument that AMI and dynamic pricing do not make sense for low-use residential customers. The *Review of CA Load Research* confirmed many anecdotal impressions of usage differentials among customers. Overall, the report provided evidence of the following:

Figure XX: California Data on Small Customer Usage

1. Customers who use under 130 percent of the California baseline[144] on average use proportionally less peak energy than customers using larger amounts.

2. Small customers have a much lower saturation of air conditioners.[145]

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[142] The Ontario pilot evaluation did not produce a breakout of demand response by participant usage or household characteristic. According to the evaluators, 85 percent of all participants (and controls) had central air conditioning, and 82 percent lived in single-family homes, *OSPP Evaluation,* at 26. It may be asked whether the strong summer critical peak result found in this pilot was the result of air conditioning response, and would not have been as strong had the participant groups not been dominated by single-family homes with central air conditioning. However, the Report does not permit a conclusion on this point.

[143] William B. Marcus, Greg Ruszovan, JBS Associates, *"Know Your Customers": A Review of Load Research Data and Economic, Demographic, and Appliance Saturation Characteristics of California Utility Residential Customers ("Review of CA Load Research"),* filing by TURN with California PUC, in App. 06-03-005, Dynamic Pricing Phase, December 11, 2007.

[144] In response to the crisis in electricity prices and reliability in 2000-2001, the California legislature passed what has become known as AB1X (Assembly Bill No. 1 from the First Extraordinary Session (Ch. 4, First Extraordinary Session 2001)). Among other things, AB1X included price protections for residential consumers using 50 percent to 60 percent of the average residential consumption, depending on climate zone. This level is known as the "baseline," not to be confused with the "baseline" usage estimated in the Ottawa Hydro pilot against which critical peak rebates were calculated by that utility.

[145] The report noted that as many as 64 percent of those using under 130 percent of baseline in the SDG&E territory do not have an air conditioner.

3. Small customers have fewer discretionary appliances. For example, over 20 percent of them do not have in-home laundry facilities.

4. Small customers' use, therefore, is more closely tied to non-peak appliances—refrigerators, lights, and electronic equipment—than that of customers who have higher usage.

5. Small customers also have considerably lower incomes than larger customers on average. On the SDG&E and Edison systems, over 50 percent of low-use customers have incomes under $40,000 per year. By contrast, the largest customers (over 1500 kWh per summer month) on average have household incomes over $100,000.

These findings are not surprising. They confirm common sense impressions of the electricity usage and socioeconomic characteristics of different households. It is not enough, however, to identify factual conditions that give rise to questions about the ability of certain users to benefit from AMI or dynamic pricing. In particular, if certain customer groups were indifferent to AMI and dynamic pricing, but other customers benefited, it would not make sense to deny such other customers the benefits of AMI.

Further, if certain customers are at risk from AMI costs and dynamic pricing impacts, but the system as a whole (and other customers) benefit greatly, the regulatory task then becomes determining if it is fair for vulnerable customers to remain at risk, and, if not, to require that utilities develop and employ tools to protect them.[146]

Finally, at least where standard non-time-varying rates are not sharply tiered, low-use customers should receive benefit from tying the price of electricity closer to the differing resource cost at different times. The very fact that they tend not to have or use the high-draw appliances (e.g. central air conditioning) means that they use proportionately less during critical peak hours than other customers. They will get the benefit of lower off-peak prices under CPP, and will not be harmed by high critical peak prices, which apply only in a very few hours.

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[146] Some would even argue that regulators have no responsibility to prevent harm to a group of customers whose rates increase because the regulator requires pricing that more closely follows cost causation, or provides some other system benefit in which such customers do not share. To the extent AMI is such a case, they would argue, it should be left for legislators to develop a system of transfer payments that move some of the net savings from AMI to those who are harmed. "One cannot make effective public policy by rejecting a program producing net benefits because it harms one group. That principle would terminate highway construction on the grounds that some people will die from accidents." Scott Hempling, Director, NRRI, personal communication with the author, December 20, 2007. Others, including this author, believe that effective modern ratemaking requires consideration of questions of affordability, even in the absence of explicit legislative mandates (as exist in some states).

The results of the California Statewide Pricing Pilot send mixed signals as to the likely response of low-use customers on average to demand-response tariffs. As analyzed by Herter, the pilot in California showed that on average, low-use customers (600 kWh/month or less) did not reduce load in response to critical peak pricing.[147] Further, Herter found no statistically significant difference in this result between low-use customers of different income levels.[148]

Charles River Associates, on the other had, found that low-use participants (50 percent or less than average daily use) in the CA SPP *did* respond on average to critical peak pricing, albeit not to the extent of high-use customers (200 percent or greater than average daily use).[149] Looking at specific housing characteristics and associated high-demand end-uses, CRA found similar patterns. According to CRA, those in single-family homes and those with central air conditioning responded more strongly to critical peak pricing than those in multifamily units and those without central air conditioning.[150] Those in multifamily housing and those without central air conditioning[151] nonetheless responded strongly to critical peak pricing.

The chart below displays these CRA 2003 and 2004 results:[152]

Figure XXI: CA SPP: CPP-F Percent Reduction in Peak Usage, by Usage Level and End-Use

CPP-F Customers by Usage/ End-uses	Year 1	Year 2
High Use	-17.2%	-14.7%
Low Use	-9.8%	-12.2%
Single-family house	-13.5%	-14.0%
Multi-family building	-9.8%	-11.8%
Central A/C	-12.8%	-17.4%

147 *Residential Implementation*, at 2126 and Figure 4.

148 *Ibid.*, at 2126.

149 CA SPP, *Summer 2003 Impact Analysis*, CRA, August 9, 2004, Table 5-9, p. 90; *Final Report*, Table 4.19.

150 *Ibid*.

151 Customers with pool pumps made large percentage reductions in their peak usage, but the results were not statistically significant, so they are not reproduced here.

152 CA SPP, *Summer 2003 Impact Analysis*, CRA, August 9, 2004, Table 5-9, p. 90; *Final Report*, Table 4.19.

No Central A/C	-12.3%	-8.1%
Average all customers	*-12.5%*	*-13.1%*

In Illinois, the relative average demand response of lower-usage and higher-usage customers was quite different from the California experience. For example, in 2003, ESPP participants in multi-family units had the highest response of all to high-price notifications. In 2004, those living in multi-family units with no air conditioner had the strongest overall demand response.[153] Those in single-family homes, with central air conditioning, had the weakest response: [154]

Figure XXII: ESPP 2004 Elasticities and % Load Reduction, by Hhld Type and A/C

Household Type	Air Conditioning	Elasticity	CPP % Load Reduction
Single Family	none	-.08	
Single Family	window only	-.08	
Single Family	central	-.052[155]	
Multifamily	none	-.117	-16% to -19% overall
Multifamily	window only	-.105	
Multifamily	central	-.087	-30% overall

These Illinois results contradict the argument that lower-usage customers cannot and will not reduce load. This conclusion is muddied somewhat by the fact that in this same year (2004), customers in multi-family units showed no statistically significant response at all to high-price notifications, in sharp contrast to their strong response to such notifications in 2003. In 2005, further, the price elasticities of ESPP participants in multi-family homes and single-family homes were similar.[156]

[153] 2004 ESPP Evaluation, Section 2.2.

[154] *Ibid.*, at 10; posting by Steven George to EEI's AMI Listserv, citing a recent presentation by Anthony Starr, in response to author's questions, December 5, 2007.

[155] First hour of CPP event only.

[156] *2005 ESPP Evaluation*, at 13. Again, the question facing policy makers is not merely whether certain groups of customers cannot respond to price signals, but rather (assuming the policy maker is concerned with the bill impacts on such customers), whether the incremental AMI costs assigned to such customers outweigh the operational benefits shared with them plus whatever share they may enjoy of resource savings made possible by those who can and do reduce load.

b. Low-income customers did exhibit demand responses on average, but there was great variation around the mean

Analysts evaluating the California SPP and the Chicago area ESPP looked at demand response by the income of the household.

ESPP did not gather information on customer income directly, but rather used zip codes to identify participant neighborhoods by relative income levels. In 2005, ESPP evaluators found no difference in demand response between customers in low-income and non-low-income neighborhoods.[157] The same evaluation, however, showed a greater demand response among customers who received their high-price notification by email on their home computer.[158]

In her paper on implications for residential customers of the California pilot, Herter shows the following 2004 summer responses, by income and household usage:

Figure XXIII: CA SPP - Mean HHd KW Change, 12 CPP Events, Summer 2004, by Household Income and Usage

Household Income	Percent CPP Event Load Reduction	
	Low-Use Customers	High-Use Customers
$0 - $24,999	-1.0%	-5.7%
$25K - $49,999	-5.6%	-40.0%
$50K +	-0.9%	-18.5%
All incomes	-2.4%	-20.8%

According to this data, 2004 CA SPP participants with incomes below $25,000 showed the weakest demand response, even those with high usage. By contrast, high-use households in the $25,000 up to $50,000 annual income group showed by far the largest response to critical peak events. As in the ESPP case, however, even low-use low-income CA SPP participants showed some demand response in Herter's analysis.[159] Also, high-usage customers in the high-income group analyzed by Herter showed moderately strong demand responses, contrary to the

157 *Ibid.*, at 15.

158 *Ibid.* While computer ownership is becoming more democratic, low-income households remain disproportionately unlikely to have computers, and hence email capability.

159 The opponents still may have an argument that AMI investments will raise bills for low-income customers higher than the cost savings they enable through demand response (even after offsetting the incremental AMI costs by the operational savings all customers will share). As will be discussed in the next section, the ability to shift load and lower bills need not be positively correlated.

assertion that high-income customers would not respond to price signals, but would "buy through" and keep their loads at previous levels.[160]

Charles River Associates performed a different analysis of CA SPP responses broken out by household income in its reports to the California PUC and Energy Commission. CRA identified only two broad income groups: those with household incomes at or below $40,000, and those with incomes at or above $100,000.[161] In 2003 and 2004, CRA found that both groups showed demand response to critical peak events, although in both cases the higher-income customers showed the higher demand response. Using the broader income categories, the CRA analysis showed a smaller difference than the Herter analysis between the responses of those at the lower income levels and those at the highest income levels:[162]

Figure XXIV: CA SPP - Demand Reductions, by Broad Income Groups, 2003-04

Higher-Income ($100K+)	-15.1%	-16.2%
Lower-Income ($40k-)	-12.1%	-10.9%

The Brattle Group also analyzed the demand response of participants by income in the CA SPP.[163] Brattle Group provided results for two categories of low-income CA SPP customers: customers by income level (self-reported), and customers on the low-income discount rate (CARE).[164] The analysts found that high-income households were somewhat more price-responsive than low-income households. They state, however, that "the difference is not substantial and low income customers showed demand response."

Statewide, according to the Brattle Group analysis, low-income CA SPP participants on average reduced their load during critical peak hours by 11 percent, whereas high-income customers reduced their load on average by 16 percent during critical peak hours. Participants statewide who did not receive the CARE discount were much more price responsive (reducing their load by about 16 percent) than those who did receive the CARE discount (reducing their

[160] Note that high-income, low-use consumers did not respond strongly to critical peak pricing.

[161] CRA also had a category for pool ownership, which probably corresponds positively with income.

[162] CA SPP Final Report, Figure 4-19.

[163] Ahmad Faruqui and Lisa Wood, "The Impact of Dynamic Pricing on Low Income Customers: A Discussion Paper," in *Impact on Low Income,* The Brattle Group, 2007.

[164] CARE is a reduced price tariff for low-income customers. Availability is restricted to low-income customers. CARE customers receive a 20 percent discount on the electric bill versus non-CARE customers. About 20 percent of residential customers in California are on the CARE rate. *Impact on Low Income,* 6.

load by only 3 percent). These results compare to price responsiveness of about 13 percent across all climate zones for all participants.[165]

The CA SPP also included a small pilot, called Track B, to examine whether low-income customers in urban neighborhoods living in close proximity to a fossil-fuel-burning power plant had different load responses if they received support in their efforts from community groups. The Brattle Group analyzed the results of the Track B pilot to develop some insights into the demand response behavior of these participants, based on income. As summarized by the analysts, on average this group of low-income customers did display at least a small amount of demand response:

> Over two summers – 2003 and 2004 – the average daily shift in usage during a critical peak day was about 1.2 percent for low-income customers in Track B in response to an information only treatment and about 2.6 percent in response to a price signal and information. To place these numbers in perspective, the average customer in the same climate zone displayed a response of 7.6 percent.[166]

The Brattle Group analysts noted, however, that four of the Track B participants cut their usage in half in response to CPP calls, and one of these reduced household demand by two-thirds during the winter period. The large reductions of this handful of participants, when averaged over the small number of participants in this pilot Track, likely skewed the average result downwards, and may even mask load increases among others in the group. These data, accordingly, do not assure regulators that all low-income customers have an opportunity to reduce their usage sufficiently in response to price signals to warrant the cost of supplying those signals.

c. Limitations on use of pilot evaluations of low-income response

One difficulty regulators face in using all these data to understand the likely CPP demand responses of low-income customers in California (or elsewhere) is the inadequacy of the evaluators' income definitions. The definitions do not correspond to any of the standard definitions of poverty. There are at least three issues that regulators would want to explore before applying these CA SPP income-response results to their own states.

First, poverty properly understood will vary by household size. It takes a higher income to feed, clothe, and house a larger number of individuals. Second, cost of living varies widely; an income that would be sufficient in one area (even within California, for example), might not be in another. Third, the lower income measures used in the above analyses are too broad to permit a realistic understanding of the ability of low-income households to respond to CPP. None of the analyses of the response to the CA SPP pilot, with the possible exception of the review of CARE customer responses, satisfactorily addressed these three issues.

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[165] *Ibid.*

[166] Ahmad Faruqui, Lisa Wood, *Impact on Low Income*, 1.

As to the definition of poverty by household size, the single most useful starting point for analysis is the so-called Federal Poverty Level (or FPL). The United States Department of Health and Human Services annually publishes the so-called Federal Poverty Guidelines. These guidelines provide a basis for allocation of anti-poverty funding, and for determining eligibility for federally-funded means-tested programs.[167]

As to the household size issue, the federal poverty guidelines handle this concern by stating a different poverty threshold depending on the numbers of persons in the household. As to the definition of poverty, it is customary in means testing to use a multiple (typically 150 percent) of the FPL, as the dividing line between low-income and non-low-income households.[168]

The FPL is adjusted annually in February. Below are the 2007 Federal Poverty Guidelines, including a calculation of the more commonly used 150 percent of FPL. Comparing this chart to the income levels used by Herter and CRA, and assuming an average household size of between 2 and 3 persons, it is possible to see that even the narrower band used by Herter includes too many households with incomes above 150 percent of the FPL. A household fitting the CRA income cut-off of "below $40,000" would have to be quite large (6 people) in order to fit the most commonly-used definition of poverty (150 percent of the FPL). [169]

The $25,000 cut-off used by Herter is a more reasonable approach than the CRA income categories; a family need only have this income and be composed of three persons to fit the definition of low-income.[170] Even so, a more granular analysis of the relationship between income and demand response would be necessary to have confidence that the results shown in California represent the likely behavior of low-income participants, even from California.

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[167] The guidelines do not vary from state to state, except that Alaska and Hawaii have higher limits, in recognition of their generally higher costs of living.

[168] Those responsible for low-income programming have long understood that 100 percent of the FPL is too low an income to sustain a minimally safe and adequate standard of living. Regulatory commissions that make use of the FPL to determine eligibility for low-income rates and programs typically use the 150 percent cut-off, or a higher level.

[169] In California, a family of four with an income at below $40,000 would qualify for the CARE low-income rate discount. Thus, CARE's income limit is approximately twice the FPL.

[170] Average household size in the United States is approximately 2.61 persons per household, according to the Census Bureau. See: http://factfinder.census.gov/servlet/ACSSAFFFacts?_event=&geo_id=01000US&_geoContext=01000US&_street=&_county=&_cityTown=&_state=&_zip=&_lang=en&_sse=on&ActiveGeoDiv=&_useEV=&pctxt=fph&pgsl=010&_submenuId=factsheet_1&ds_name=DEC_2000_SAFF&_ci_nbr=null&qr_name=null&reg=&_keyword=&_industry=

Figure XXV: 2007 U.S. Poverty Guidelines

Persons in Household	**48 Contiguous States/ D.C.**	***150 % of FPL***	**Alaska**	**Hawaii**
1	$10,210	*$15,315.00*	$12,770	$11,750
2	13,690	*20,535*	17,120	15,750
3	***17,170***	***25,755***	21,470	19,750
4	20,650	*30,975*	25,820	23,750
5	24,130	*36,195*	30,170	27,750
6	27,610	*41,415*	34,520	31,750
7	31,090	*46,635*	38,870	35,750
8	34,570	*51,855*	43,220	39,750
For each additional person, add	3,480	*This column derived.*	4,350	4,000

SOURCE: *Federal Register*, Vol. 72, No. 15, January 24, 2007, pp. 3147–3148

The pilots provide some curious data with respect to the concern sometimes voiced that low-income customers tend disproportionately to be heads of household who remain in the home during the day, and thus are necessarily on-peak electricity users. The ESPP evaluation noted that a greater demand response was observed among households where a larger number of persons were at home during the critical peak period.[171] By contrast, Ontario pilot customers with small children who stayed in the home reported to evaluators that they found it difficult to shift such electricity-using activities as laundry off the critical peaks.[172] Understanding better the reason for such apparent differences in the experiences of stay-at-home customers with families in the two pilots would shed valuable light on a commonly-heard worry about time-of-use pricing.

d. Customer disability creates vulnerability as well.

Finally, on the impacts of demand response pricing on vulnerable customers, AMI opponents raise the specter of elders fearing to turn on their air conditioning in a heat wave. The inability of socially- or mentally-disabled customers to recognize dangerous conditions and take steps to ward off the risks may be a larger concern than the financial situation and age of the customer. None of the pilots, however, was designed to shed light on the question of how dynamic pricing will affect those who, for reasons of mental or social disability, are not in a position to respond to price signals, or even disconnect notices.

[171] 2005 ESPP Evaluation, 15.

[172] OSPP Final Report, 52.

Anecdotal evidence from three heat waves in recent history in which large numbers of customers perished suggests that fear of the cost of air conditioning was not the main reason for the failure of most victims to use it at the time of the heat wave. Nor were the victims predominantly elderly.[173] Rather, many who suffered heat stroke and died in recent heat waves were in their 40s and 50s. A number of these individuals lived in make-shift housing without air conditioning, some had no air conditioner to turn on, and some who avoided using air conditioning for reasons of frugality did not, apparently, do so because they were unable to pay for it.[174] The underlying reasons, based on newspaper accounts and some scholarly studies, were not so much poverty as social or mental disability.

For example, many who perished in recent heat waves were men living alone without the support of a social network, and some had mental health problems. One elderly woman who died from heat stroke resisted turning on her air conditioner, according to her children, because she had grown up in post-war Germany under conditions of terrible privation, and would not allow herself what she considered a luxury, although she could afford air conditioning. Similarly, the recent death of an elderly Michigan woman in the winter as the result of lack of heat due to an electric utility disconnection did not result from an inability to pay. Rather, both the customer and the daughter living with her (who survived) suffered from mental impairments. Neither was capable of paying the bill, although the customer had funds on hand.

Thus, bill affordability among elders may not be a key concern with time-varying pricing. At the same time, regulators and utilities should be concerned about the impact of dynamic pricing on vulnerable customers. Precisely because of the potentially diminished ability of mentally or socially disabled customers to take rational steps in response to challenging circumstances, the regulator and the utility cannot protect such customers by implementing demand-responsive tariffs on an opt-out basis. Only an opt-in rule will prevent such customers from potentially being left on a rate that they cannot manage effectively.

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[173] The author recalls reading press reports following the Chicago heat wave of 1995 to the effect that some elders perished because they could not afford air conditioning but feared opening their windows because they lived in high-crime neighborhoods. I was unable to obtain confirmation of these reports for this paper.

[174] See, e.g., Jennifer Steinhauer, "California Heat Wave Ends With a Death Toll Near 25," *The New York Times*, September 7, 2007, available at http://www.nytimes.com/2007/09/07/us/07heat.html; Hank Shaw, "Victims of S.J.'s fatal heat wave had so many things in common," August 20, 2006, *The Record OnLine,* available at http://www.recordnet.com/apps/pbcs.dll/article?AID=/20060820/NEWS01/608200331/-1/a_special07 ; KR Kaiser, CH Rubin, AK Henderson, MI Wolfe, S Kieszak, CL Parrott, and M, Adcock, *Heat-related death and mental illness during the 1999 Cincinnati heat wave*, Am J Forensic Med Pathol. 2001 Sep;22(3):303-7; JC Semenza, CH Rubin, KH Faltern, JD Selanikio, WD Flanders, HL Howe and JL Wilhelm, *Heat-related deaths during the July 1995 heat wave in Chicago*, Am J Prev Med. 1999 May;16(4):269-77; Eur J Public Health. 2006 Dec; 16(6):583-91.

5. How persistent, year over year, are the voluntary load shifts or reductions resulting from price signals, with or without smart meters?

With the exception of the Illinois ESPP, which operated for three successive years, none of the recent real-time pricing pilots operated for more than one or two summers. In the California SPP pilot, time of use prices began July 1, 2003; the pilot was over by end of summer 2005.[175] The Ontario pilot was even shorter: August 1, 2006 to February 28, 2007. The lack of a track record of persistent demand responses over a number of years casts doubt on the reliability of the findings from these pilots.

Although it lasted three years, the Illinois ESPP did not provide a full opportunity to study consumer reaction to numerous permutations of weather and price. The pilot did not begin until August 2003. And, as Summit Blue candidly stated in its evaluations of the ESPP pilot, the two first summers unusually low temperatures meant that firm conclusions about residential customers' response to RTP would have to await experience during a more normal (i.e., hot) summer.[176]

The third summer of the ESPP was much warmer than normal; record high gas prices were driving up electricity prices.[177] Certainly, the 2005 ESPP pilot was a better test than the 2003 and 2004 pilots of residential responses to typical critical peak prices, because participants in the hot summer of 2005 faced the unpleasant choice between persistent sweltering heat and expensive peak electricity. Even the 2005 data cannot answer the ultimate question of whether observed effects will persist over time.[178] In particular, it would be valuable to see how residential customers respond to real time pricing (and even to direct load control) if they are subjected to high peak prices summer after summer, and face the need to pay higher bills or cut back on air conditioning and other end use comforts every hot summer.

The recent experience of Puget Sound Energy (PSE) with time of use pricing suggests that public acceptance may still be a difficult hurdle for pricing initiatives, at least those that do not produce bill savings for those on the rate. After a pilot phase, PSE put all 300,000 of its residential customers on its Personal Energy Management (PEM) program in 2000, on an opt-out basis, in response to the crisis in the Western markets. For almost a year, PSE's program received positive response from customers. Under the program, customers were charged an on-

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[175] There are some data on responses of customers on CA SPP rates after the end of the pilot, but no there is published report on such data of which this author is aware.

[176] Customers who participated in ESPP in 2003 showed no decline in response in 2004.

[177] 2005 ESPP Evaluation, at ES-1.

[178] In addition, the costs of AMI will have to be recovered from consumers regardless of whether the weather (and related peak demands) is warm enough (or cold enough, as the case may be) to drive the system towards the levels of peak demand, and associated resource costs, that were assumed in developing a cost-benefit justification for the AMI investment.

peak summer rate 6.25 cents per kWh and an off-peak rate of 4.7 cents, plus a $1 incremental monthly charge to be on the rate.

Few customers chose to opt out of the PSE program at first, and participants reported high levels of satisfaction. However, once they began receiving comparison bills in late 2002, opt-outs increased rapidly.[179] After a public outcry in protest against the rates, customers rapidly abandoned the program. As Kiesling explains, the issue for customers was that, "for most of them, even though they had shifted their use of electricity, their bills had either not gone down, or had actually gone up compared to what they would have paid under the old rate."[180]

The Puget Sound Energy experience is consistent with the reports by customers in the three pilots reviewed here that reducing their bills was a key driver in their participation in the demand response programs. To the extent this short-term bill impact focus remains a dominant source of demand response, the success of any program will be vulnerable to the bill impact experience of participants. AMI and associated demand-response pricing options may fare better in those areas of the country where the alternative would be increasingly sharp cost increases for generation, at marginal prices well above the Puget Sound 6.25 cent on-peak rate.

Concern about persistence of results also stems from the observation that much of the pilots' demand response can be attributed to a minority of participants. All three pilot evaluations noted that the average reductions were made up of large decreases from some participants, with more modest reductions by some participants, and no reductions from many on the tariff (if not also increased usage from some). The more "average responses" are driven by extraordinary reductions by a small number of customers, the more reason there is to question whether such customers can achieve the pilot levels of load reduction year after year, at least at pilot levels.

Looking at the self-reported changes made by CA SPP participants as they responded to price signals,[181] there is further reason to wonder if lifestyle changes made in a pilot setting will persist once the novelty wears off. Customers in California reported little in the way of self-perpetuating demand response. Fewer than 10 percent of participants stated that they turned their air conditioner thermostat up; and only a little over 10 percent stated that they turned off their air conditioning or used it less to reduce peak usage. For all pilot pricing groups, the largest single change reported in usage was shifting clothes laundering to off peak hours (between 30 percent and a little over 40 percent of participants mentioned this technique for peak load reduction). Without minimizing the contribution of a number of small-impact changes

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[179] Kiesling, *Prospects and Challenges*, at 33.

[180] *Ibid.* It might also be that the easing of the Western market difficulties (and low hydropower water problems) by late 2002 reduced the sense of public crisis that led consumers to accept new ideas for addressing electricity costs in Washington State.

[181] Momentum Market Intelligence, *SPP End of Summer Survey Report (Draft*), January 21, 2004, p. 31.

customers reported making (such as turning off lights and using appliances less during peaks), it is safe to ask whether the high-yield responses will persist year after year.[182]

Utilities that promoted residential real time pricing in the 1980s saw that participation in voluntary time-sensitive tariffs eroded over time. Ralph Abbott, now President of Plexus Research, Inc.,[183] has worked on utility time-of-use programs for residential customers since the mid-1970s. In 2005, he sounded a cautionary note about TOU pricing for residential customers, stemming from his experience with the promotion of TOU rates during that earlier period.[184] He cited research performed for the Electric Power Research Institute (EPRI) to the effect that acceptance of TOU by residential customers was extremely limited.

For example, the cited EPRI survey from 1985 found that most utilities offering voluntary residential TOU rates had participation rates of less than 1 percent. A 1991 EPRI report produced similar results. While about 78 percent of the utilities surveyed offered some type of voluntary residential time-of-use price, only 1.4 percent of the residential customers of reporting utilities were served on such rates in 1990.[185]

Abbott states that many major utilities had more customers on TOU rates in 1984 or 1991 than they did in 2004. He cites the experience of a large Northeast utility that had more than 26,500 residential customers voluntarily taking service under TOU rates in the mid-1980s, but by 2004, only 11 customers remained on these rates.[186]

Abbott argues that there are a number of reasons for this erosion of participation:

1. Optional TOU rates were not well-promoted.
2. Peak periods were so long that a majority of the customers' usage would occur on peak, and be subject to the higher prices.

[182] McDonough and Kraus argue that energy efficiency initiatives, such as the replacement of incandescent bulbs with compact fluorescents, produce load reductions that are more persistent over time than those achieved through time-varying pricing. Catherine McDonough and Robert Kraus, "Does Dynamic Pricing Make Sense for Mass Market Customers," *Electricity Journal*, Vol. 20, Issue 7 (August/September 2007).

[183] *Deciding on "Smart" Meters: The Technology Implications of Section 1252 of the Energy Policy Act of 2005,* prepared for the Edison Electric Institute, September 2006.

[184] Ralph E. Abbott, "Time-of-Use Rates: Sideburns and Bellbottoms?" *Energy Markets*, July/August 2005, pp. 6-8.

[185] *Ibid.* The EPRI study also calculated that each such customer used, on average, 1374 kWh per month, a very high amount for residential customers, and (if the mean and median were close) probably indicative of the use of central air conditioning and/or electric space heat.

[186] *Ibid.*, p. 8.

3. The ratio of peak to off-peak prices made the rate a "no-win" for consumers – the cost to the consumer (in dollars, convenience, lost opportunities or otherwise) of shifting load off-peak was not compensated by avoiding sufficiently high peak prices.
4. The charge for incremental metering costs ate up the savings potential.

Abbott concludes with his impression that consumers who chose the TOU rate simply wore out and lost interest after a few years.[187] Based on these observations, Abbott questioned whether time-sensitive pricing for residential customers is no more than a fad that is bound to fade over time, as the earlier implementation of such rates did. In this article, Abbott did not address the potential impacts of (1) reduced metering costs, (2) offsetting operational savings, (3) improved capability to target demand-response pricing to critical peaks, and thereby (4) reduce the extent of inconvenience to customers taking service under such pricing and (5) increase the differential between off-peak and peak pricing. These factors, as he has noted,[188] would tend to improve the chances that today's demand-response pricing options will achieve acceptance among consumers, and lead to persistent demand responses.

There are additional reasons to have reason to believe that customer response to dynamic pricing will be stronger today, and last longer, than was the case with TOU pricing from the 1980s and earlier.[189] The increases in residential peak usage today are driven by increased penetration and use of air conditioning, which can now be cycled off conveniently using fairly inexpensive control technology, without, it appears, producing great discomfort. In this author's opinion, the most hopeful development is the narrowing of the period of very high prices to a relatively few hours in the year, thus minimizing discomfort, as well as the penalty of paying such prices if the customer cannot or will not reduce load.

Critical peak pricing, made possible by technological advances in metering and communications systems (albeit not requiring AMI), allows the utility to limit the number of high-priced hours during which customers would face price signals intended to stimulate load shifting. Critical peak pricing simultaneously heightens the differential between this focused critical peak price and non-CPP prices (thus making avoiding the critical peak more beneficial to the customer). Also, among the public there is a renewed concern about rising energy costs and looming environmental consequences of energy use that has prompted many regulators to explore new options for load reduction. A variety of factors make it likely that, despite occasional dips in resource costs, the trend in system costs will continue up, and electricity costs will not drop sharply as they did in the 1990s. For this reason, the economic benefits of demand response will likely continue at a high enough level to justify price time-of-use price differentials sufficient to incent at least some demand response.

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[187] *Ibid.*

[188] Email to the author, January 30, 2008.

[189] Roger Levy notes that TOU rates offered by utilities in Arizona have attracted "upwards of 30 percent customer participation." Email to the author, January 30, 2008.

6. If taking service under time-varying tariffs is voluntary, what portion of residential customers is likely to choose such pricing?

In order to estimate the demand response savings likely to flow from implementation of AMI and time-varying pricing facilitated by AMI, it is necessary to estimate the numbers of customers likely to take service under such rates.[190] There are essentially three ways in which time-varying pricing can be presented to customers.[191] First, all customers of a given class can be placed on such rates on a mandatory basis. Second, customers can be placed on the rate, but given the opportunity (perhaps with certain conditions such as a minimum time on the rate) to opt out of being on the rate. Finally, customers can be given the choice to opt in to the rate.

If the time-varying tariffs are mandatory, the calculation of the portion of customers in a given class taking the rate is simple: 100 percent. What remains is the estimation of the average response of the entire group of customers. The estimation of the portion of customers that will take the rate over time is more complicated where the customer has a choice about whether to go on the rate.

Leading analysts estimating the resource value of AMI-facilitated time-varying pricing argue that over time, 80 percent of customers placed on opt-out time-varying tariffs will remain on the rates, and 20 percent of customers who must affirmatively opt to take service on such rates will do so.[192] The authors give no evidence that supports such estimates. As discussed above in Section III, no pilot has operated for long enough to provide a basis for projecting long-term participation rates. Time-of-Use rate experience from the 1980s and 1990s cannot provide encouragement to plans that rely on large minorities of residential customers opting in to demand-response rates, even though there are important differences between such TOU rates and the needle-peak approach of critical peak pricing. The difficulty that California utilities experienced in attracting potential participants into the CA SPP also suggests that opt-in tariffs may not attract large groups of customers.

Some cite the experience of Puget Sound Electric, which offered an opt-out time-varying price during the western market crisis in 2001. Initially, 90 percent of customers remained on this rate.[193] By November 2002, however, the utility asked the regulator for permission to scrap the entire tariff as the result of public pressure from customers complaining that their bills were

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[190] Utilities and regulators will also need to know the likely demand response patterns of customers who will voluntarily choose to stay on the rate or opt for the rate, if taking service under the rate is not mandatory. This report does not address the issues involved in estimating these values.

[191] For present purposes, it is not important to determine who would present the pricing to the customers, regulators, utilities, both, or others.

[192] See, e.g., Ahmad Faruqui and Stephen George, *Quantifying Customer Response to Dynamic Pricing*, and Ahmad Faruqui et al,, *The Power of 5 Percent*.

[193] Lynne Kiesling, *Prospects and Challenges*, at 2.

slightly higher on the time-varying tariff than the standard rate (bills averaged 80 cents per month higher on the TOU rate.) Customers thus "opted out" en masse, rather than customer by customer.

7. What are the likely bill impacts from dynamic pricing, on average and for various subgroups of residential customers?

It is not possible to read any of the evaluations of the three pilots discussed here and come away with an understanding of the likely bill impacts of the tariffs and AMI implementation. This inconclusivity is a serious flaw in all the analyses, undermining their usefulness as guides to regulators in other states. A regulator may, of course, determine that an investment is cost-effective overall, and that the resulting tariffs fairly allocate the costs and benefits of the investment, even though there are winners and losers among the customers depending on their ability (or willingness) to take advantage of opportunities to avoid high-price periods. Regulators will want to understand the bill impacts on classes of customers and subgroups within each class, however, if for no other reason than to gauge the likely public response to approving (or mandating) the investment and related tariffs.[194]

One cannot simply look at the levels and percentages of demand response by customer group, and infer that bill impacts will correspond. The entire design of a tariff, and the usage patterns of different customer groups, have as much if not more to do with bill impacts as the customers' different responses to critical peak events.

In addition, not all the evaluations even attempted to estimate bill impacts.[195] Where evaluators did estimate bill impacts, they simply ignored the incremental cost of the meters (not to mention the additional costs that a full AMI installation would entail). Given that total meter costs can run as much as $7 per month (depending on the AMI configuration and the extent of back-office software revisions), and that operational benefits may not even cover 50 percent of such costs in some service areas,[196] ignoring meter costs is bound to skew the results of any bill

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[194] Strength of character is essential for a regulator, who must from time to time take positions that are unpopular but that advance principles such as efficiency. At the same time, regulators must manage their "political capital" well, in order to be successful in achieving policies consistent with such principles. In addition, regulatory principles have long included considerations of price stability and public acceptance. See James C. Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961), at 291; republished on the web (July 2005): http://www.terry.uga.edu/bonbright/publications.

Further, even where legislators have not required explicit consideration of affordability or universal access to service, regulators in a number of jurisdictions take care to limit the burdens of regulatory policy on vulnerable customers where they can.

[195] There are no bill impact analyses in the ESPP evaluations.

[196] As where a utility already installed automated meter reading (AMR), or where labor costs for meter reading are especially low, for example.

impact analysis. Further, even without accounting for metering and incremental AMI costs, the bill impact analyses presented in evaluations of the various pilots showed that some customers would see bill increases as a result of the institution of (mandatory) time-varying pricing.

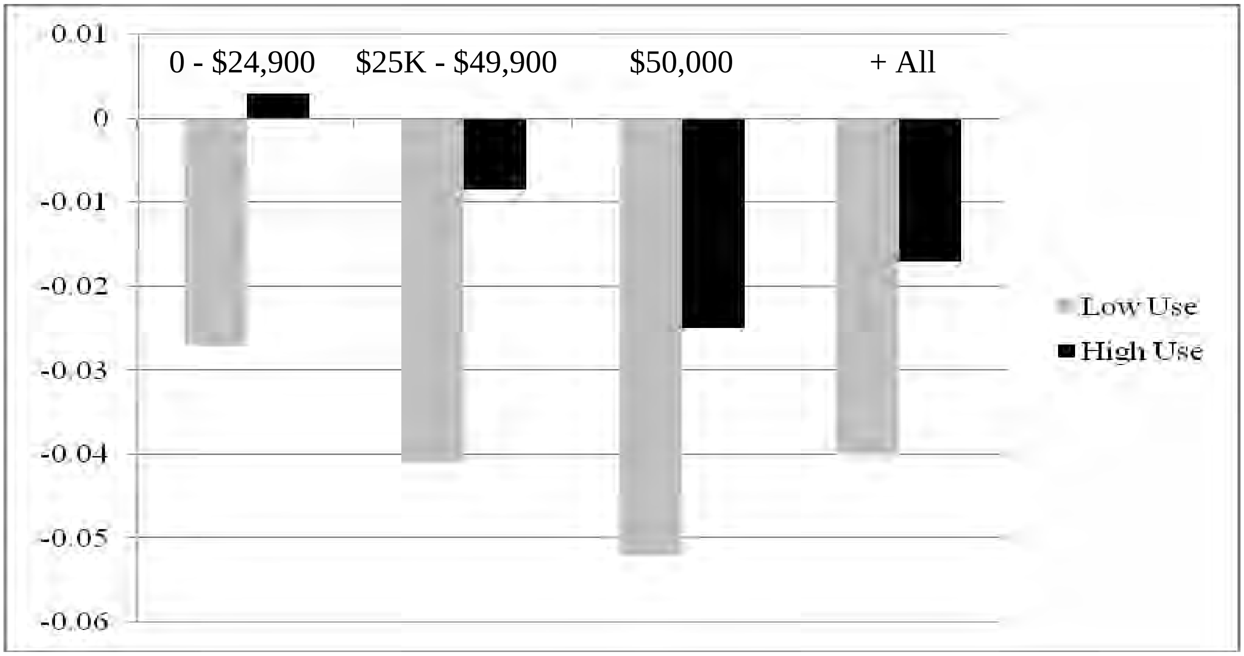
Evaluations of the California pilot show that, not counting AMI costs, low-use customers of all income brackets studied enjoyed bill reductions as a result of the dynamic pricing offered to participants. Indeed, while they did not reduce their demand as sharply as did high-use participants, they enjoyed larger bill reduction benefits, again not counting AMI costs. These results bear out the advice of some AMI/dynamic pricing proponents, who note that because low-use customers have a higher load factor, they will benefit from the lower off-peak prices accompanying CPP, even if they cannot avoid as much usage on the peak as higher usage customers.[197]

Most high-use customers also enjoyed bill reductions in the CA SPP. However, one group actually saw bill increases overall. As can be seen in the chart below, lower-income/high use participants on average experienced bill increases, even though they reduced demand on average. The fact that this group included lower-income customers is reason for some concern. Further, the bill reductions experienced by the two lowest income groups of the high-use participants were effectively zero, even without counting the incremental costs of AMI investments, according to the Herter analysis.[198]

[197] *See, e.g.,* Roger Levy, *Demand Response: Tariffs, Rates and Incentives,* a presentation to the ACEEE Summit on Emerging Technologies in Energy Efficiency. October 27, 2006. Note, however, that in California, this relationship did not hold, because under the standard five-tier inverted block rate, very low-use customers enjoyed very low prices for their usage. SPP TOU and critical peak pricing eroded these price benefits. See, e.g., *PG&E AMI Final Opinion,* CA PUC Decision 06-07-027, July 20, 2006, at 46.

[198] *Residential Implications,* 2127-2128. Statistically, the bill differences observed for these participants were not significantly different from zero.

Figure XXVI: Mean Annual Change in Bills by Usage and Income (Without AMI Costs)



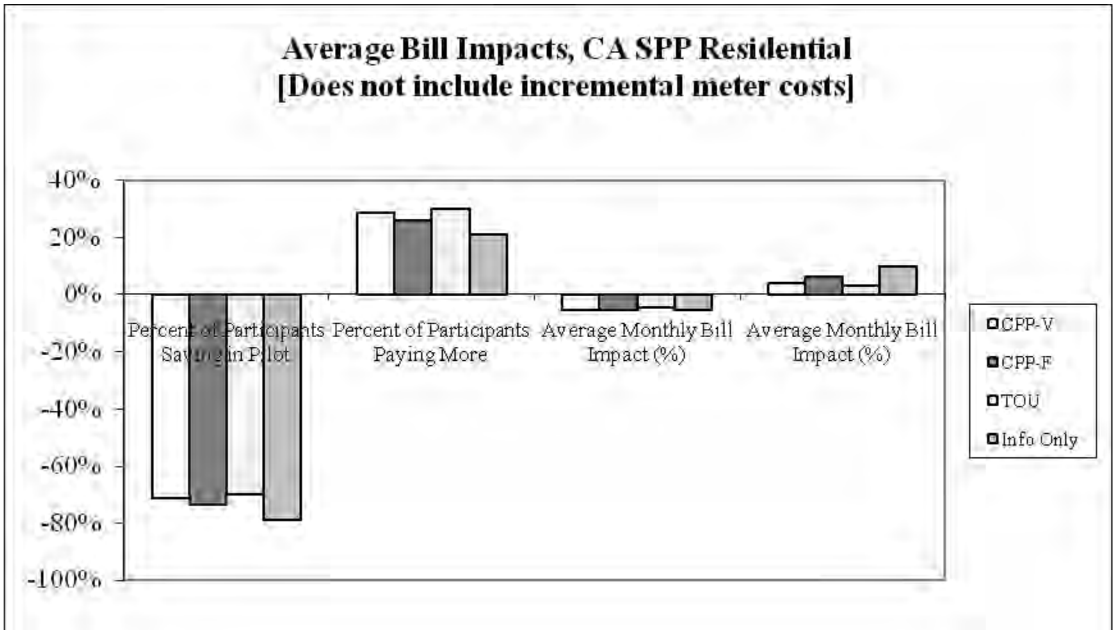
Source: Herter, *Residential Implementation*, Figure 5

Herter suggests that, given these findings, those considering a full-scale CPP implementation "might focus efficiency and education efforts on high-use, low-income customers."[199]

Twenty percent or more of the participants in all CA SPP pilot groups saw bill increases, even without counting incremental AMI costs. These results suggest that, at least in the absence of a CPR/PTR rebate option, there will be some net losers on time-varying rates.

[199] Ibid. Roger Levy also suggests collecting incremental metering costs on a volumetric basis, *Demand Response.*

Figure XXVII: CA SPP Bill Impacts by Tariff Type



The Ontario evaluators did not break out bill impacts by income or other participant characteristics. As in the California case, they ignored meter costs.[200] Without considering meter costs or conservation effects,[201] over the course of the experiment 75 percent of the participants paid less than they would have on the ordinary non-pilot prices. In August, however, the average bill impact across all three price-groups was an increase relative to what their bills would have been without the pilot pricing. It was also in August that the largest number of OSPP participants experienced a significant increase.

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[200] As noted above, in Section III, the utility was already recovering the costs of interval meters in rates as part of a government-mandated initiative to install such meters in every customer's premise. In August, Hydro Ottawa filed its Application for cost recovery of its advanced metering program with the Ontario Energy Board. The Application reflected the decisions of the Energy Board in December 2006 and the January 29, 2007 "Addendum For Smart Meter Rates" on allowed cost recovery of advanced metering required by the government policy. These orders prescribed a formula for calculating the cost of the advanced metering system, and required recovery of allowed costs through a uniform adder to the customer charge for all customers of a given utility. The Application reflected an increase from the 2006 rates (C$0.41/mo. for all residential customers and C$0.83/mo. for non-residential customers) to a uniform C$1.74/mo. for all customers. The U.S. and Canadian dollars are presently near parity. The Application is available at: https://www.hydroottawa.com/PDFs/HydroOttawa_APPL_20070208.pdf.

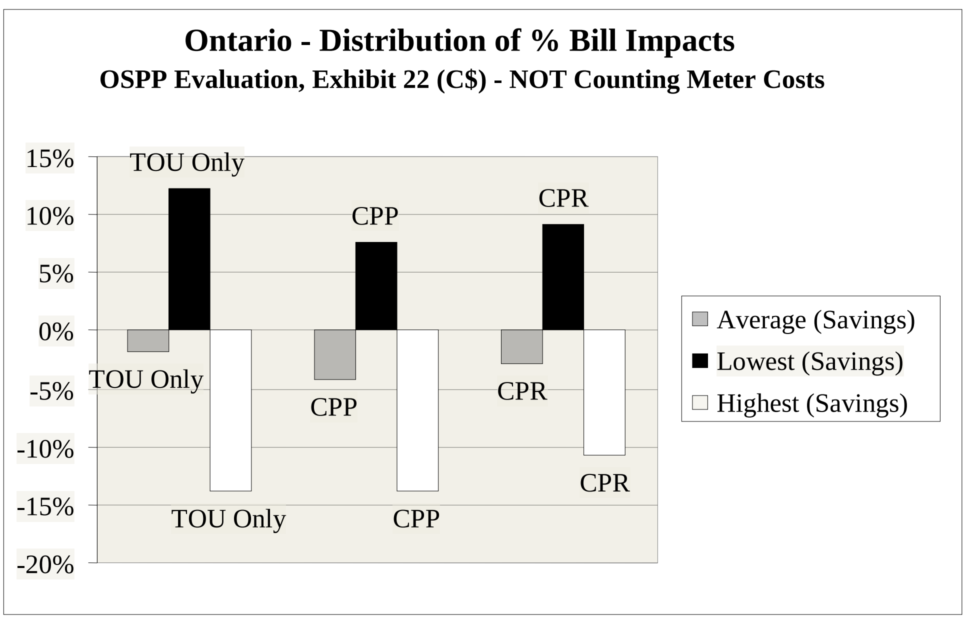
[201] But also not including the metering costs (which were considered sunk costs).

Such increases reflect the fact that for these Ontario participants, the higher pilot tariff peak prices did not encourage demand response. These August cost impacts were outliers, according to the Ontario program evaluators. Of the approximately 2625 statements issued over the course of the pilot, only 5 percent showed savings greater than C$8.84. Similarly, only 5 percent of statements reflected bill increases greater than C$3.46. Over the year, one participant experienced an increase as high as C$12.81, while some participants saw savings as great as C$35.55.

Assuming a 6.0 percent reduction in usage based solely on the conservation effect, and with an average price of C5.9¢/kWh, the evaluators estimated that conservation savings ranged from a few cents for the lowest volume user to over C$6 per month for the largest user.

The distribution of bill impacts reported for the Ontario pilot is shown in the chart below. As can be seen, on average over the entire pilot period, but again not including metering/AMI costs, participants saved on their bills. This was generally true whether they were on the TOU rate, CPP, or CPR. However, in each group, there were participants who experienced very large bill increases:

Figure XXVIII: Ontario SPP - Distribution of Bill Impacts (Excluding Meter Costs)



For the reasons discussed above, it is necessary to take the findings of pilot participant bill reduction with a grain of salt.[202] Failure to consider incremental metering costs calls into question whether these pilot results shed any useful light on the bill impacts of AMI in the case

[202] The OSPP finding of bill increases associated with peak usage increases is likely robust, however.

where a utility has no advanced metering in place. Even without correcting for this major defect in the analysis, it appears likely that in these analyses, participant bill savings are overstated, and that bill increases to at least some participants are understated. The evaluations also show that some customers, while perhaps a minority, will face sharp bill increases if dynamic pricing is introduced.

Further, assuming that the bill impacts observed in the pilots are representative of the impacts of a real implementation of AMI and related pricing, the question remains whether such results are consistent with sound or sustainable regulatory policy. Do these bill increases reflect the efficient allocation of costs to cost-drivers? If so, does equity (or long-term rate acceptability) require some mitigation of AMI-driven bill increases? It is not possible to answer this question in the abstract. Attempting the estimation of corrections to the bill impact analyses available deserves further research.

E. If past is prologue, critical peak and other time-varying pricing will produce "winners" and "losers."

As discussed above, not all participants reduced load, and in some cases participants' critical peak load went up during the pilot. For example, some ESPP participants did not show any load response at all to the pilot pricing option. As with the Track B (low-income San Francisco neighborhood) results in California, in the ESPP a small number of customers with large load responses drove up the average response rate.

We can view this fact as a glass half full, or a glass half empty. On the positive side, this experience suggests system-wide benefits do not depend on getting all or even most customers to respond to price signals; the strong response of a small number of customers can drive benefits for the entire system. On the negative side, system benefits are vulnerable to changes in the response of the few "star" responders.

Further, if it is necessary to provide potential star responders all the system benefits associated with their demand response in order to induce that very demand response, then non-responding customers will see higher bills (from any incremental AMI costs not covered by operational savings), but may be unable to create (and receive their share of) system resource benefits. Regulators must understand how likely it is that the utility will have to flow all system benefits back to demand responders, as opposed to setting critical peak prices (or rebates, as the case may be) at a lower level, thus allowing some of the system benefits of responders' demand reductions to flow to other customers and offset incremental AMI costs.

If there are groups of customers who cannot take advantage of demand response opportunities, but there are no system benefits to share with them because all such benefits must go to potential responders, then it will be more difficult to gain public acceptance for AMI. The pilots do not answer the question whether it is necessary to set critical peak prices equal to the avoided costs of critical peak usage.

The utilities in California set the critical peak prices in their respective service territories to meet three Commission goals, none of which included matching of the critical peak price with marginal cost at critical peak periods.[203] In Ontario, the critical peak price was set at a level intended to approximate the avoided costs of such usage. The C30¢ critical peak price was calculated as the average of the costs of the highest 93 hours of the previous year.[204] In Chicago, the Cooperative and ComEd designed the critical peak tariff to vary with day-ahead forecasts of system costs, up to a rate cap implemented to prevent extraordinarily high bill impacts.[205]

In the Central Maine Power alternative regulation case now pending, Dr. George testified that the full value of demand reductions would be $1.25 per kwh, whereas the utility proposed to set the critical peak rebate at 75 cents/kWh (implicitly leaving 40 percent of the avoided capacity benefit of their load reductions on the table for other customers). He further stated that a utility should be willing to provide 100% of avoided cost benefits to those who make them possible (here, by demand reductions).[206] But that argument presumes that it is both fair and feasible to ask all customers to pay for an infrastructure that only some will be able to use.

On the other hand, even low-income customers who have little load to shift may emerge no worse off from implementation of AMI, and taking service under a critical peak pricing tariff, than they were without such pricing. Such could be the result if (1) operational savings are a high proportion (e.g. 75 percent or more) of the total savings needed to justify AMI investment, (2) such customers have the typically flat load profile of low-use customers, and (3) not all such savings are needed as incentives to those who can shift. In such a case, bill increases from the incremental AMI costs may be offset by bill decreases for superior load profiles plus a share in

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[203] Consistent with PUC requirements, the utilities observed three key criteria in setting the critical peak rates: (1) maintain revenue neutrality for the average usage customer, (2) minimize bill impacts due to a change from existing rates to the pilot rate, and (3) provide a meaningful incentive for customers to reduce load. Interim Opinion in Phase 1 Adopting Pilot Program For Residential And Small Commercial Customers, *Order Instituting Rulemaking on Policies and Practices For Advanced Metering, Demand Response and Dynamic Pricing*, California PUC Rulemaking 02-06-001, June 6, 2002, available at: http://docs.cpuc.ca.gov/published/Final_decision/24435-03.htm.

[204] In the Pacific Northwest GridWise™ pilot, program managers set RTP customers' programmable thermostats to respond to price offers that changed every 5 minutes with changing system costs, according to a schedule of "comfort settings" that specified when the customer would reject the program price offer. If the price offer was too low to merit loss of the controlled end-use (water heating or space heating/cooling) according to the customer's comfort setting, the thermostat would "reject" the offer, and override the control. *PNNL Final Report*, at vii. Such a market approach could allow customers to shift load off peak at less than marginal costs. Determining whether this result occurred in the Olympic peninsula pilot is beyond the scope of this report.

[205] 2004 ESPP Evaluation Final Report, at ES-5.

[206] Stephen S. George, *Rebuttal Testimony on Behalf of Central Maine Power Company*, Docket 2007-215, Appendix A, p. 9.

the benefits of other customers' demand response. In a particular circumstance, the result could be no bill changes for low-use customers, or even decreases.[207]

Conversely, those who can shift large amounts will be winners. This result is likely to hold even if incremental AMI costs per customer are at the high end. The combination of high-use customers' share of operational savings, and the flow-through to them of at least a large share of the system resource cost savings their demand response creates, will likely more than offset their allocated AMI costs.

The California pilot results suggest that the customers in greatest danger of experiencing bill increases are low-income, high-use customers.[208] Pilot participants in this group, for reasons the pilot evaluations do not make clear, did not or could not shift enough usage off the critical peaks to avoid bill increases from the switch to a critical peak price.

The regulator may ignore the complaints of those who can shift without discomfort or danger, and choose not to do so.[209] The regulator will face a tougher set of choices if there are a number of customers who simply cannot shift their load, at least without serious discomfort, and whose load profiles mean they will see increased bills upon introduction of TOU or critical peak pricing.

Also, as is discussed above, these pilot results do not constitute conclusive proof that dynamic pricing and load control tariffs will bring forth similar levels of demand response, in other settings, with other customers, or over a longer period of time. A regulator will have to look behind the averages to the experience of subsets of customers, and look for data of response persistence, to understand whether such pricing will be valuable in other states.

F. Miscellaneous Additional Issues

As noted in Section I, above, this report has not attempted to address all the issues that a regulator will face when considering whether to approve AMI investments. Regulators may not find some of these issues readily resolvable, but nonetheless they will play a major role in determining the relative costs and benefits of AMI, and the public acceptability of the time-varying prices initiated using AMI technology. We merely list them below.

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[207] Such a result begs the question of whether such pricing could be achieved, with these felicitous results for small customers, without the entire AMI investment.

[208] This inference is not inconsistent with the ESPP observation that customers in multi-family units and customers without central air conditioning showed the largest response to critical peak price signals. Evaluator Summit Blue did not identify a group of low-income, high-use customers in this Chicago-area pilot.

[209] That is not to say that such customers will be powerless to exert political pressure on the regulator in any given instance.

1) What is the useful life of an AMI system installed today? What is its economic life? AMI technologies are new and evolving. How can we be sure of the length of their useful lives? If cost savings over years, if not decades, are necessary to justify the investment, is it prudent to go forward with the investment in the current state of technological development?

    a. To what extent should the Commission attempt to direct the selection of technologies, and associated functionalities? Should a regulator specify, for example, that the utility shall use a particular network architecture for the interactive communications component of a utility's AMI?

    b. Should a Commission encourage or require the system be open to use by non-utility parties?

2) What is the energy usage effect of dynamic pricing? What are the implications of such usage effects for generation fuel costs? For environmental compliance?

3) How do consumers get the benefit of energy and capacity avoidance, in states where most customers' power is procured through all-requirements contracts (such as are used in most restructured states with default service procurements)?

4) How should basic service procurement processes and contracts be revised to reflect allocation of the benefits of anticipated demand reduction?

5) How does demand reduction facilitated by AMI get credit, if at all, in regional power pools and markets?

6) Where a utility in a retail competition jurisdiction provides its non-shopping customers with monthly prices, rather than annual flat rates over 6 months or more, does it make sense to install a major new metering, data management, and communications infrastructure, when most of the benefits shown in at least one pilot came from avoiding the hedging premium that competitive suppliers add to bids for default service in that competition state?[210]

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[210] Catherine McDonough and Robert Kraus, in their article "Does Dynamic Pricing Make Sense for Mass Market Customers?" *Electricity Journal*, Vol. 20, Issue 7 (August/September 2007), n. 22 and accompanying text, citing the *Direct Testimony of Bernie Neenan on Behalf of Citizens Utility Board and the City of Chicago*, ICC Docket No. 06-0617, October 2006, 21, to the effect that 83 percent of the benefits achieved via demand reductions in the ESPP pilot were attributable to avoiding the wholesale suppliers' risk premiums for flat rate default service.

7) To the extent that demand response is a means of hedging against premiums charged in the market by suppliers for flat rate service, are there better ways of reducing those market premiums?[211]

8) By what rate design should incremental metering costs be recovered?

   a. Flat rate per customer, as is now common for metering costs, or
   b. On a volumetric basis, to protect low-use customers?

9) How should ratepayers be assured of the benefits of reduced operating costs?

10) What limitations, if any, should be applied to a utility's use of remote termination and reconnection?

11) How should the critical peak price or the critical peak rebate be developed?

   a. Should it be set to flow the entire benefit of avoiding capacity to the demand-shifting customer, or should it be based on some other consideration?

   b. For example, should it be set only as high as needed to secure a desired level of demand response, with the balance of the avoided cost shared with the ratepayers generally? Used to hold vulnerable customer harmless? Shared with the utility or supplier as an incentive to foster demand response?

   c. How should the utility estimate the value of the resource costs avoided by the load shifting?

12) What is the extent of undepreciated meter, data management, communications, and other investments that would be rendered obsolete by the investment in AMI?

   a. Who should pay these costs? Ratepayers? Shareholders? Both, via some sharing, as is typical in the case of canceled plant? Should the answer to the question depend to any extent on whether the utility has demonstrated that the investment is cost-effective?

   b. Over what amount of time should abandoned meter and related costs be amortized?

13) How can analysts be encouraged to present data in a way that makes it possible to make comparisons between utility AMI implementations? For example, which manner of presentation of demand response results should analysts use: elasticities or percent load?

[211] David Boonin, then-President of TBG Consulting, testified before the Pennsylvania Public Utilities Commission that the supplier premiums for hedging the variation in costs as they provide flat rate service to basic service customers are overstated by as much as 15 percent. *Comments on Mitigating Electric Price Increases*, Pennsylvania Public Utility Commission, M-00061957, June 2006. Mr. Boonin has since joined NRRI as the Chief of the Electricity division.

14) Should utilities be allowed pre-approval of AMI investments? If so, should regulators require an explicit sharing of the risk that costs will be higher than estimated by the utility, and benefits lower?

IV. Conclusions and Recommendations

A. What answers have we found to our key questions?

At the start of this report, we listed a number of key areas of uncertainty regarding time-varying pricing (offered using AMI) and residential customers:

1. To what extent did residential customers, on average, reduce load in response to time-varying pricing and direct load control in the pilots?

2. To what extent were the participants in the three pilots representative of residential customers, including particular subsets of such customers?

3. Did low-use or low-income customers respond to time-varying pricing differently from other customers?

4. How persistent, year over year, are the voluntary load shifts or reductions resulting from price signals, with or without smart meters?

5. If time-varying tariffs are voluntary, what portion of residential customers is likely to choose such pricing?

6. What are the likely bill impacts from time-varying pricing, on average and for various subgroups of residential customers?

Based on the information we have reviewed, we offer the following answers:

Figure XXIX: Summary of Answers to Key Questions

Question	Summary Answer
1	Overall, residential customers displayed significant demand reduction in response to critical peak prices. Customers with direct load control devices (such as programmable communicating thermostats) responded at dramatically higher rates (up to 41 percent on critical peak days) than those without such automated control devices (between 10 percent and 15 percent on average). Response of residential customers on average to time-varying pricing varied from group to group, and time to time. In some cases, the mean response was higher than the median (some particularly strong responders pulled the average response up). It is likely that within the averages, individual customers and subsets of residential customers showed widely varying responses to critical peak pricing. Not all responses to time-

	varying prices were demand reductions. In at least one pilot, participants on average increased usage during certain critical peak periods, despite critical peak pricing and critical peak rebate pricing. In one pilot, half the participants showed no response at all. CPR customers responded to critical peak rebate opportunities, but showed a lower response to critical peak rebate opportunities than CPP customers showed to critical peak prices.
2	Participants in the time-varying pricing pilots were roughly representative of the customer base from which they were drawn, but it is not possible to rule out self-selection bias in the results. Participants were in some cases skewed towards higher-usage, higher-income customers.
3a	Lower-use customers in general reduced their load by lower percentages than higher-use customers. One analysis of California results showed that low-use customers did not reduce loads at all in response to critical peak pricing; another analysis of the same data showed low-use customer response, but not at the same level as for high-use customers. Results were mixed for residents of multifamily buildings, who tend to be among lower-usage households - in the ESPP and OSPP, such customers at times responded more strongly than those in single-family homes. In the California SPP, residents of multi-family homes responded to critical peak pricing, but at lower levels than residents in single-family homes. Low-use customers of all income groups had the highest bill reductions, not counting AMI costs.
3b	Lower-income customers in general reduced load by lower percentages than higher income customers. Results are not definitive about the impacts of CPP or PTR on low-income customers, because income bands in pilot evaluations were not well defined. In one pilot showing strong low-income response, practically all the response came from a handful of customers. In the CA SPP, lower-income/high-usage customers increased usage on critical peak days.
4	The pilots do not provide a basis for estimating how persistent the observed demand responses will be year over year. Past experience with time-varying rates is discouraging on this point, but perhaps not indicative of likely persistence of response over time, given today's less expensive metering and demand response technologies, the ability to isolate high peak prices to a narrow set of critical peak hours, and the ability to program end uses to respond to prices communicated by the utility.
5	Pilots to date provide no useful information regarding the likely participation rates of voluntary time-varying tariffs. Optimistic estimates of 20 percent migration to opt-in time-varying rates and 80 percent opt-out retention rates have no basis.
6	None of the pilots provides readily available information on likely bill impacts of AMI, in that none addresses the allocation of incremental customer costs and time-varying resource cost savings to participants and non-participants. This omission is a major gap in the research to date, and hampers regulators trying to anticipate how an overall positive cost-benefit calculation for AMI will translate to specific customer groups. Findings of

	lowered bills from time-varying pilot prices must be discounted by the fact that the cost side of the equation ignored AMI costs. Even without counting AMI costs, 20 percent or more of the CA SPP participants on all pilot rates saw higher bills. In the Ontario SPP, 25 percent of the participants had no bill decrease, or had bill increases, on the time-varying tariffs. Among customers with higher bills in the Ontario SPP, CPR customers had larger increases than CPP customers.

The results of several pilots, then, show that residential customers, on average, have responded strongly to various types of dynamic pricing. Critical peak pricing, in particular, has shown promise as a demand response tool for residential customers generally.[212] Also, customers with uses suitable for load control, such as central air conditioning, and who have smart thermostats installed to automate the demand response to price signals, responded much more strongly than other groups. However, not all pilot participants reduced load, not all groups reduced load on average in every circumstance analyzed, and in some cases participants' critical peak loads went up during the pilot.

Bill impact information is necessary if for no other reason than to gauge popular acceptance of more dynamic pricing. Here, the pilot data is virtually useless, because none of the pilots reflected those incremental AMI costs that would be counted against incremental demand response resource cost savings. Even without reflecting this added cost, some customers experienced high bill increases at certain points in the pilots. For a variety of reasons, low-income, high-use customers in at least one pilot experienced large bill increases, again without considering the bill increases associated with that portion of AMI not offset by operational savings.

Also, only time will tell whether the results observed in these pilots will persist into the future.

Because of (1) the uncertainties over persistence of demand response under critical peak pricing or rebates, (2) the lack of specific information from the pilot reports about the identity of possibly vulnerable customers (making it hard to determine whether and if so how to mitigate potential harm to such customers), (3) the relatively small portion of estimated AMI costs that can be covered by operational benefits in some cases, and (4) questions about the extent to which those responding to critical peak prices must receive the entire benefit of their load reductions, leaving no benefit for other customers, it is not possible to conclude that AMI makes sense in all circumstances.

Greater efforts to induce persistent critical peak demand reductions are necessary, as future costs of capacity and energy are on track to keep going up. Whether AMI makes sense as the tool to incent demand response is very much open to question. As one utility official put it:

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[212] This report does not focus on time-of-use rates, as such rates did not call forth the strongest responses in the pilots, and also can readily be implemented without investing in a complete advanced metering infrastructure.

> The root question is whether the goal is to install AMI (thus the question that started this discussion) or reduce generation levels and system peaks through conservation and/or DSM practices? Fully integrated AMI is not required to enable time-of-use and CPP rates nor is it required for most DSM programs. Several DSM programs add significant energy savings through [other means].[213]

B. Recommendations

As this report shows, residential customers on average can and do respond to time-varying prices. This experience, coupled with the understanding that AMI can offer large operational savings to many utilities, gives reason to hope that AMI's costs can be offset by cost reductions. There remains a great deal of uncertainty, however, regarding the persistence of demand responses induced by time-varying pricing. There remains uncertainty about net bill impacts on residential customers as a group if Critical Peak Pricing or Peak Time Rebates are offered, and if AMI is installed in order to support such tariffs. Further, there remains uncertainty about the useful lives of AMI components, and thus the net present value of AMI costs.

We acknowledge the uncertainties facing a regulator in evaluating AMI and its alternatives. There are two ways a regulator can resolve these uncertainties and decide what action to take: go ahead with AMI approval, or wait until experience elsewhere answers some of the questions about AMI's useful life and the persistence of resource savings from demand response initiatives undertaken using AMI. Neither approach involves authorizing further pilots.

Conducting a pilot at this point would duplicate work that has already been done and is being done elsewhere, without adding appreciably to the understanding of the remaining issues. It would instead be useful to analyze in more detail the vast amounts of information developed by the three pilots reviewed here (and the others mentioned in passing). Perhaps some of the questions could be answered with additional analysis. For example, it may be possible to do a better job of isolating demand response of low-income households, or estimating bill impacts for all residential customers under different assumptions about AMI costs and cost-recovery approaches.

Regardless of whether a regulator goes ahead with AMI approval or decides to wait until the persistence issues are better resolved, it would be useful to identify the vulnerable customers, and consider how a utility might enable them to avert any unfair impacts of an AMI investment, or even just a time-varying rate structure. This work needs doing. Even if it is done, however, the question remains as to whether the effects observed in these pilots will persist. Only time will provide the answer to that question.

In determining the relative costs and benefits of AMI and associated demand response initiatives, one key difficulty facing the regulator is that the arguments pro and con require a

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[213] Douglas Marx, Pacificorp, posting to EEI AMI listserv, September 2007.

determination of so-called "legislative fact," rather than mere "adjudicative fact."[214] In other words, the arguments center around what costs of the AMI and related investments *will be*, what consumer reactions *will be* to various pricing designs, how long such demand responses *will last*, whether and to what extent such changes in usage *will or will not* reduce the costs of producing electricity, what the operational savings from substituting AMI technology for meter readers and other labor *will be*, and whether changes in operations (particularly remote disconnection) represent an advance or a retreat for consumer protection *as a policy matter*.

Most of these issues require answers about what the future will bring. With respect to forecasting likely residential customer behavior, the answers may be based on examples from the past, or on regulators' beliefs about how consumers act in response to different types of prices, or on any other information from which inferences can reasonably be drawn. But the determination of this and the other cost-benefit issues requires the commissioner to make predictions. Such predictions are legislative facts, and cannot be determined in advance with certainty.

What remains is a choice about whether to lead consumers in taking on the AMI risks that time-varying pricing will not succeed as a demand response tool and that AMI costs will prove greater over time than now forecast.

There are enormous challenges facing regulators, electric utilities competitive suppliers and ultimately electricity consumers today: high incremental generation construction costs, high fuel costs, high incremental transmission and distribution infrastructure costs, new and potentially quite expensive environmental constraints on generation, to mention only a few. Some of these pressures are not likely to abate, and will instead intensify over time. Against this background, it could make sense for a regulator to pay some public goodwill and political capital out in the form of leadership in the area of demand response and operations technology, taking the risk that the uncertainties about the costs and benefits of AMI will be resolved against AMI's cost-effectiveness.

It is not likely to require as much political skill to persuade utilities, consumers and other stakeholders to accept time-varying pricing as it has been historically. According to the pilot results, participants expressed satisfaction with pilot time-varying pricing by overwhelming

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[214] According to Kenneth Culp Davis, groundbreaking author on administrative procedures:

> Adjudicative facts usually answer the questions of who did what, where, when, how, why, with what motive or intent... Legislative facts do not usually concern the immediate parties but are general facts which help the tribunal decide questions of law and policy discretion.

Kenneth Culp Davis, <u>Administrative Law Treatise</u> (1st ed1958), § 12:3 at 413, cited in Richard M. Levin, *The Administrative Law Legacy of Kenneth Culp Davis*, Washington University in St. Louis, School of Law, Faculty Working Paper Series, Paper No. 04-06-02, June 15, 2004, at 5.

majorities. Some of the historic common sense arguments against time-varying pricing need to be re-examined. Contrary to common assumptions about who can take advantage of peak pricing signals, residential customers in more than one dynamic pricing pilot have successfully lowered demand in response to critical peak pricing. Even low-use and low-income customers have, on average, lowered usage significantly in some circumstances. Low-usage customers also benefit from a relatively flat load shape. It is, in principle, possible to identify and assist customers who are both low-income and high-usage, to prevent them from experiencing major bill increases as a result of an AMI investment and subsequent implementation of time-varying prices.

On the other hand, a regulator could look at the same data and conclude that, at least until some years pass (and demand response from California customers and those in other jurisdictions implementing time-varying pricing remains strong), demand response should not be counted towards the benefits of AMI. In the meanwhile, the regulator should encourage other forms of utility demand response activity.

For example, the dramatic results for customers with programmable communicating thermostats (producing demand responses 50 percent higher than prices alone) may well be achievable by direct load control, implemented without the interposition of AMI's advanced meters and sophisticated communications networks. Similarly, critical peak pricing and rebates could be offered on a targeted basis to customers most likely to respond strongly, using advanced meters but not the rest of the AMI technology. Especially where a utility already has harvested labor savings from automating the meter reading function, AMI may not be cost-effective, and these other alternatives should be pursued.

The best course will vary from service area to service area, from utility to utility, from time to time. Doing nothing about demand response is not an option, in light of the enormous costs that a small amount of peak load shaving can avert. This author tends to be cautious, and considers that utilities seeking approval to recover major investments in rates without a reliable cost-benefit justification should shoulder the risks associated with the uncertainties that remain. With this background in mind, the following are some recommendations that emerge from this review of issues surrounding AMI for residential customers:

Figure XXX: Recommendations

1. Where automated meter reading has already been installed, regulators should not authorize cost recovery of Advanced Metering Infrastructure until results from California and other states with widespread AMI and time-varying rate options demonstrate persistent and large resource savings from time-varying rates.
2. Regulators should require a full analysis of the merits of AMI whenever a utility requests cost recovery.
3. Where the analysis of costs and benefits of AMI leaves doubt about its net value, regulators should require utilities to take the risks associated with such uncertainty, if they wish to move ahead with AMI.
4. Regulators should not require further pilots before implementing or deciding not to implement AMI.

5. Regulators who have decided not to authorize expenditures on AMI at this time should require periodic updates from utilities concerning levels and persistence of demand responses among customers of utilities with ongoing pilots or full-scale implementation of AMI, and updated information available as to the impact of such AMI investments and any time-varying pricing plans implemented using such AMI on residential customers generally, and on especially vulnerable customers in particular.
6. Regulators should require utilities to develop and implement aggressive, cost-effective demand-response programs, including efficiency as well as Direct Load Control.
7. Regulators should seek access to underlying data on pilots that have been operated to date, and arrange for this data to be analyzed to develop reliable estimates of (a) bill impacts of AMI and time-varying pricing on different groups of residential customers, and (b) the extent to which customers reduced their demand by taking steps that would be difficult to take year after year.

Appendix: Further Reading

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In the Matter of Delmarva Power & Light Company's Blueprint for the Future Plan for Demand-Side Management, Advanced Metering, and Energy Efficiency, Blueprint for the Future Application and Plan, filed February 6, 2007. P.S.C. Docket No. 07-28.

In the Matter of Delmarva Power & Light Company's Blueprint for the Future Plan for Demand-Side Management, Advanced Metering, and Energy Efficiency, Report for Delaware: Advanced Metering Business Case Including Demand-Side Management Benefits, filed August 29, 2007, Del. P.S.C. Docket No. 07-28.

In the Matter of Delmarva Power & Light Company's Blueprint for the Future Plan for Demand-Side Management, Advanced Metering, and Energy Efficiency, Report: Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs, Prepared by the Brattle Group for Pepco Holdings, Inc., filed September 21, 2007, Del. P.S.C. Docket No. 07-28.

Formal Case No. 1002, In the Matter of the Joint Application of Pepco and the New RC, Inc., for Authorization and Approval of Merger Transaction, Letter to Dorothy Wideman, Secretary, Public Service Commission of the District of Columbia, from Anthony C. Wilson, on behalf of the Smart Meter Pilot Program, Inc. (Smart Meter Pilot Program Tariff Application), filed June 1, 2006.

Formal Case No. 1002, *In the Matter of the Joint Application of Pepco and the New RC, Inc., for Authorization and Approval of Merger Transaction*, Response of Pepco and SMPPI to the Issues Raised by the Public Service Commission of the District of Columbia in Order No. 14045, September 21, 2006.

Formal Case No. 1002, In the Matter of the Joint Application of Pepco and the New RC, Inc., for Authorization and Approval of Merger Transaction, Order No. 14166, January 12, 2007.

Home Area Network Workshop

Grant Gilchrist

Consulting Engineer
EnerNex Corporation

grant@enernex.com

Agenda

- Introductions
- Context Setting
  - EPRI Consumer Portal Project Overview
  - California Influence – AMI Reference Design
- Industry Response
  - OpenAMI Overview
  - UtilityAMI Overview
- OpenHAN
- AMI-SEC

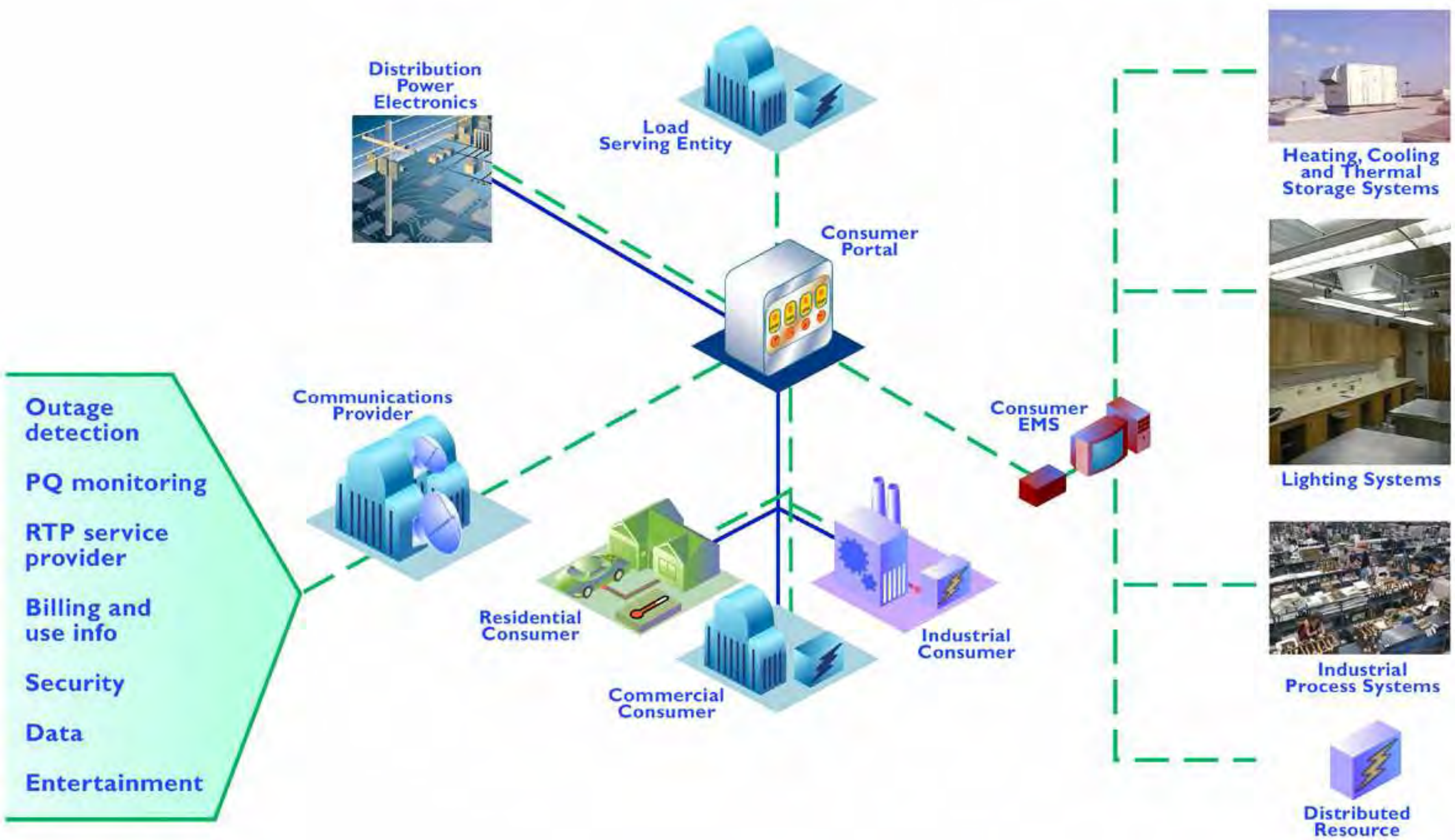
EPRI Consumer Portal Overview

- Questions before proceeding?

Consumer Portal FAQ

- What is a Consumer Portal?
- Why are we talking about portals?
- How would a portal be used?
- What could portals do?
- Which functions of a portal are most important?
- How could portals make money?
- What could a portal look like?
- What do YOU think?

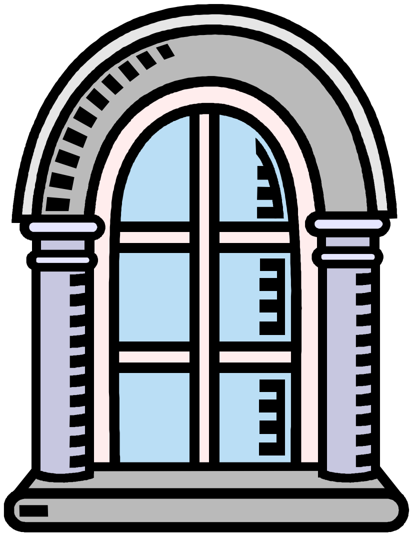
What is a Consumer Portal?



"A combination of hardware and software that enables two-way communication between energy service organizations and equipment within the consumers' premises."

What is a Consumer Portal?
More Possible Definitions

- A "***router***" that just forwards messages
- A "***gateway***" that translates technologies
- A "***single point of access"***:
  - ***From*** multiple organizations
  - ***To*** a variety of customer premises equipment
- A "***virtual device***" that may be located in:
  - A meter
  - A thermostat
  - A PC
  - A set-top box
  - All or none of the above
- A "***window***" into the customer site



Why are we talking about portals?

- Frustration
  - Too many failed attempts
  - Proprietary systems
  - Unable to deploy on large enough scale
- Regulation
  - California, Ontario, New York, etc.
  - Trying to “level the playing field”
    - Reduce barriers for vendors
    - Make costs common to all
    - Ensure common service for consumers
- Evolution
  - Recent events putting pressure on the grid
  - Must find a way to adapt

Why are we talking about portals?
The Power System is Under Pressure!

- Reliability
  - 2003 Northeast Blackout
  - The grid is "brittle"
- Security
  - Terrorist attacks
  - The grid is vulnerable
- Markets
  - Deregulation, opening of energy markets
  - Unprecedented sharing of data
- Consumer Demands
  - Distributed generation, green energy, need for hi-quality power
  - Consumers are demanding a say in the operation of the grid

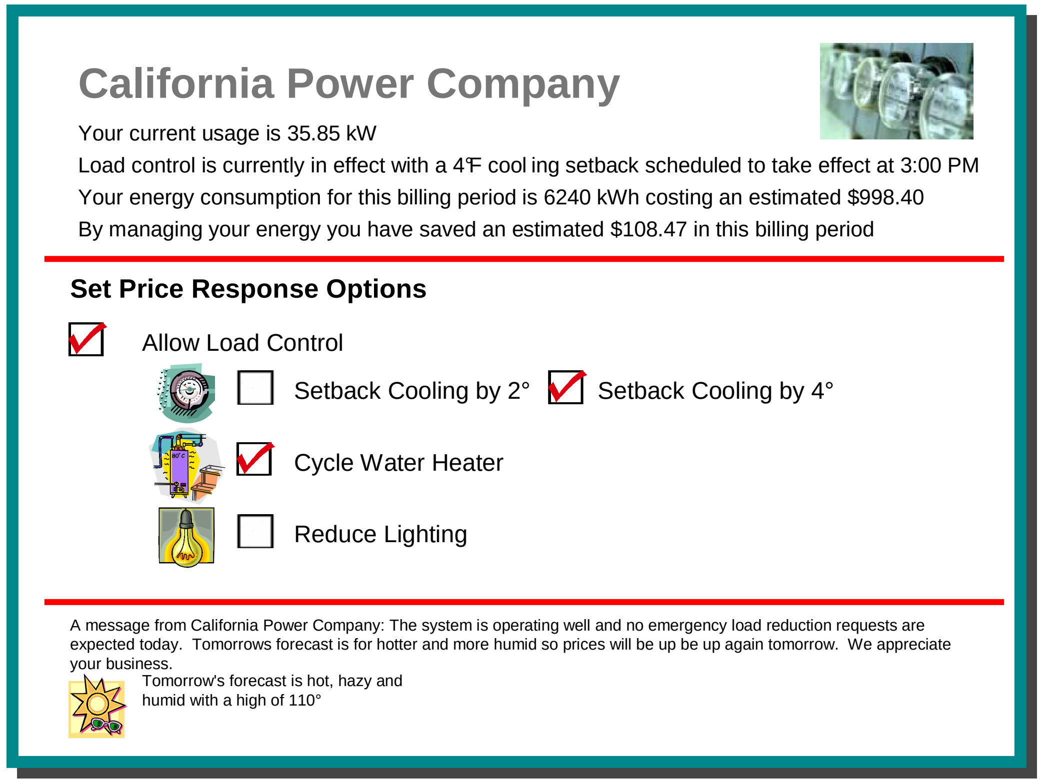
Why are we talking about portals?

Portals Lead to an Intelligent Power Grid

- The IntelliGrid Consortium:
  - A group of Utilities, vendors, researchers and governments
  - Goal is a grid communications system for a "digital society"
  - Has developed an architecture: www.epri-intelligrid.com
  - Intended to address the pressures discussed here
  - A grid that automatically ***predicts*** failures, ***heals***, ***optimizes***, and ***interacts*** with customers
- Where does a consumer portal fit in?
  - High volumes of timely, accurate information
  - Gathered from millions of customer sites
  - Enables more responsive simulation, modeling, optimization, prediction, and markets

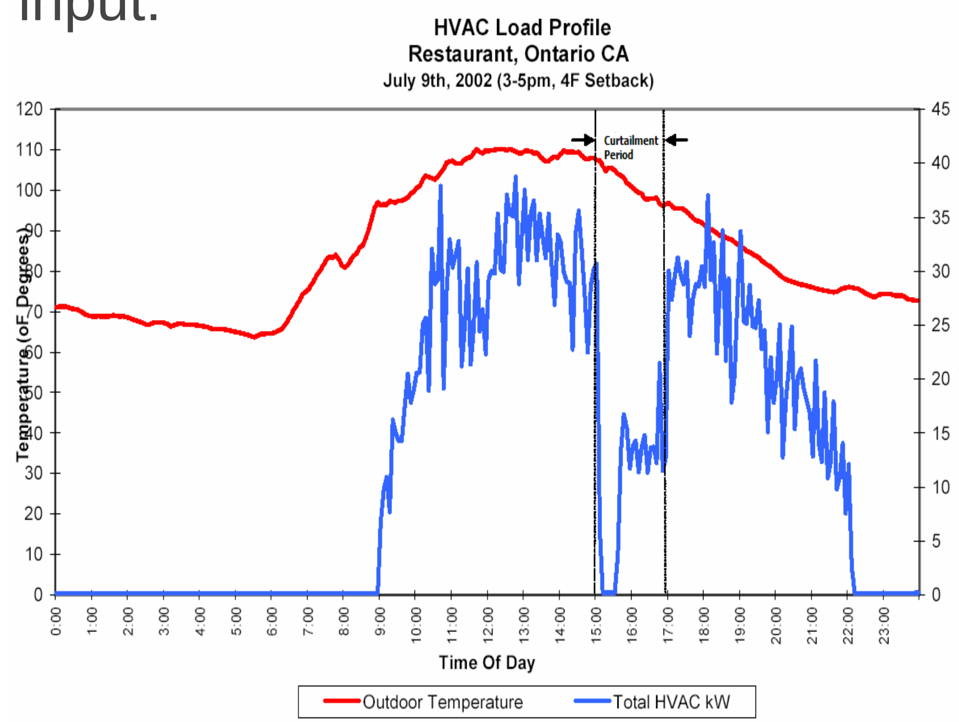
How could a portal be used? A scenario.

- A “heat storm” is due tomorrow
- Energy service provider notifies consumers that a “super peak” tariff is coming
- Consumer previously told the portal how to react
- Some consumers permitted to bid into the load reduction market



How could a portal be used?
The Response

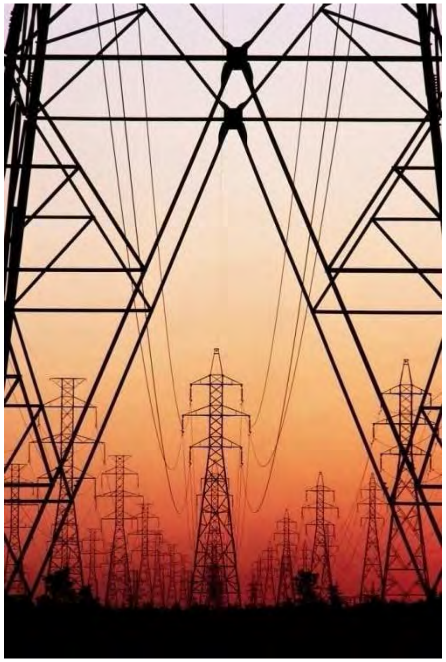
- Portal adjusts load when the new rate hits:
  - Increases thermostat setting
  - Turns off water heater
- User could have provided input:
  - Viewed the tariff change
  - Adjusted settings
  - Viewed $$ savings
- But not necessary!
- Portal reacts anyway.



How could a portal be used?

An Emergency

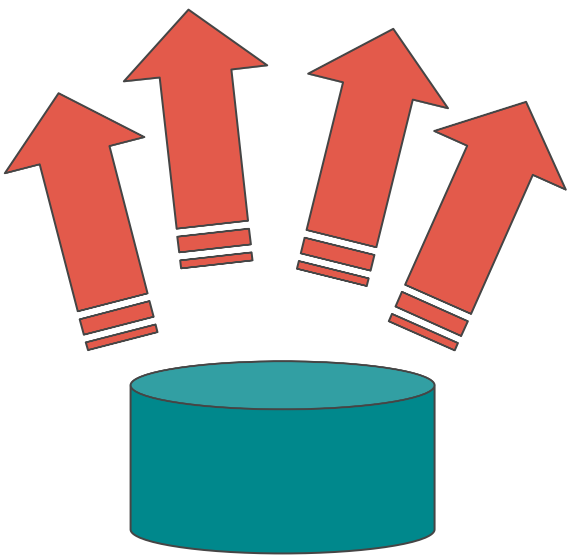
- Tree contact causes transmission line fault
- Transmission lines overloaded
- ISO issues load reduction request to portals
- Each portal cuts back load drastically
- Distribution operator queries all portals in the area
- Extent of the outage becomes clearly visible
- Operator acts quickly to partially restore power



What could portals do?

A portal could have many clients:

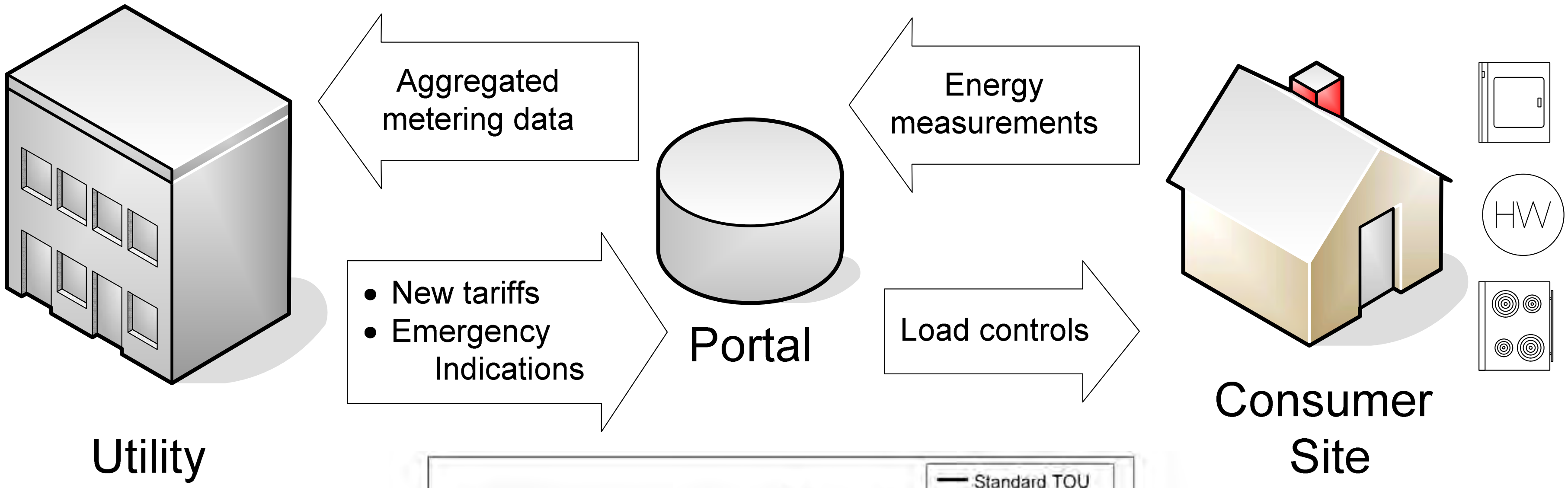
- Residential and commercial consumers
- Energy service providers
- Independent system operators
- Distribution companies
- Other utilities
- Non-utility organizations
- Others

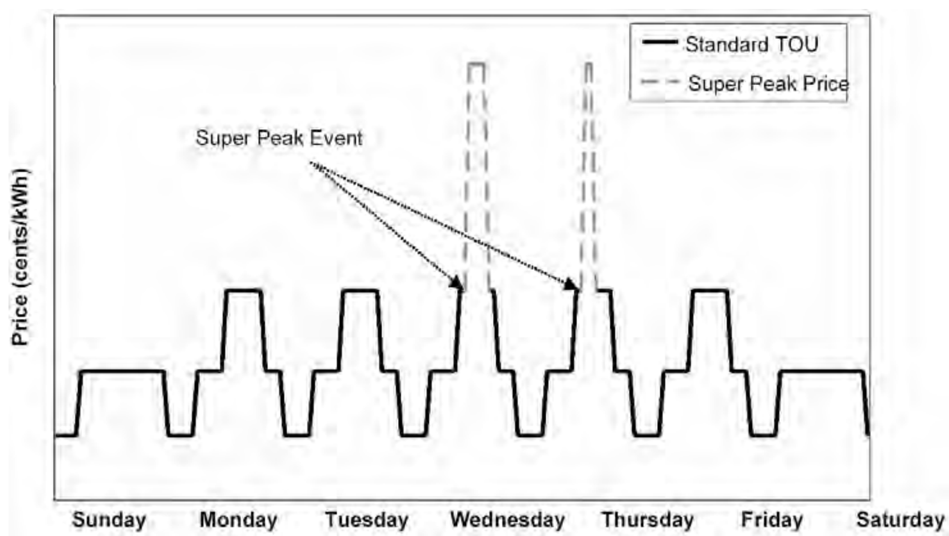


Each of these clients could use it differently.

What could portals do?

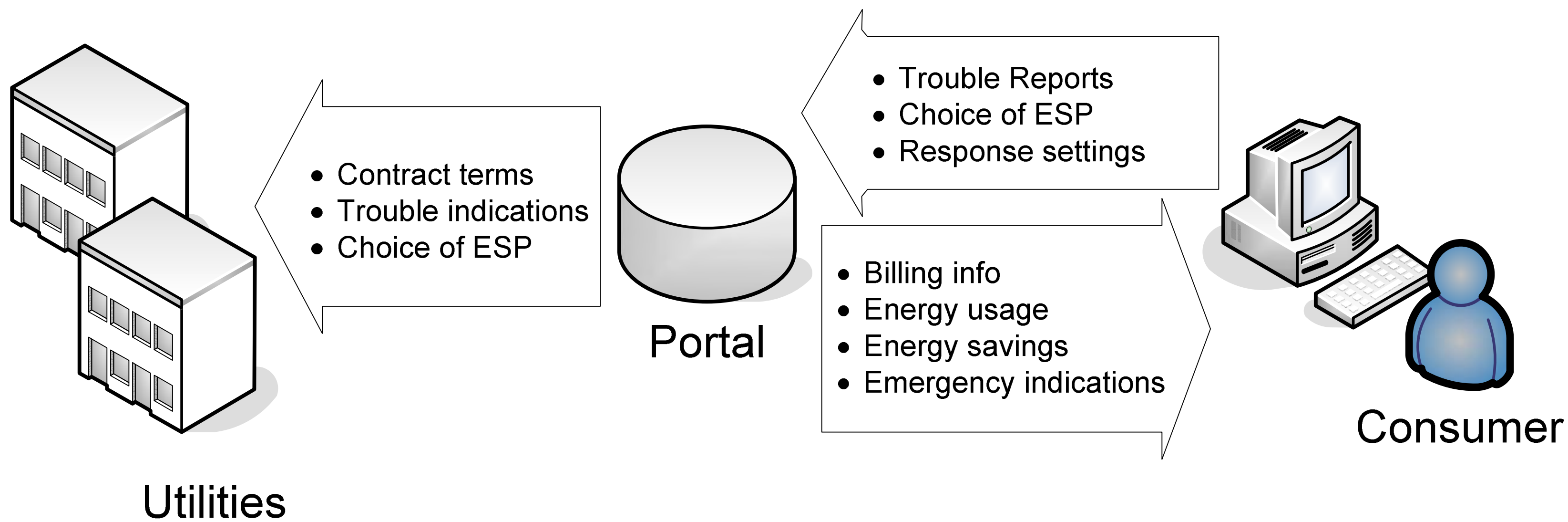
Advanced Metering and Demand Response



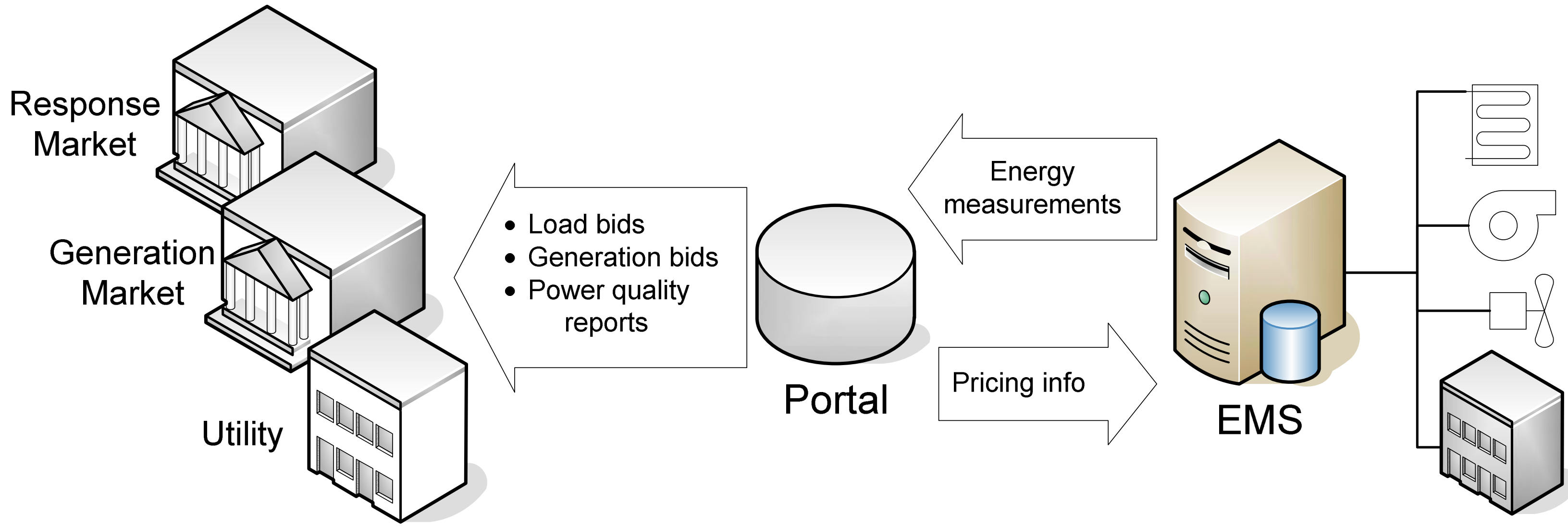


What could portals do?

Residential Customer Services

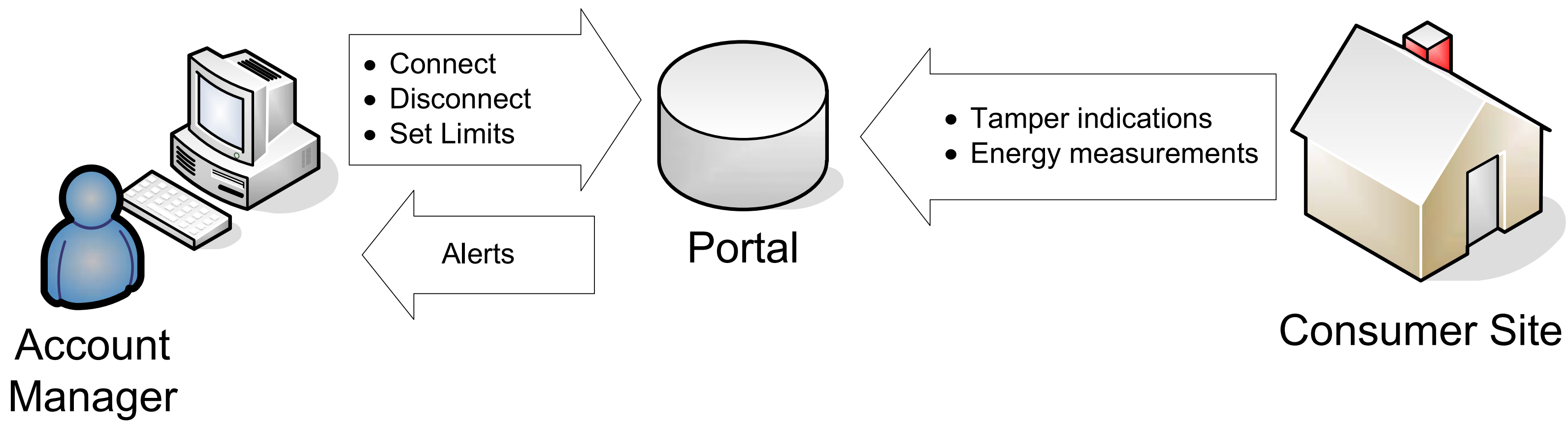


What could portals do?
Advanced Customer Services



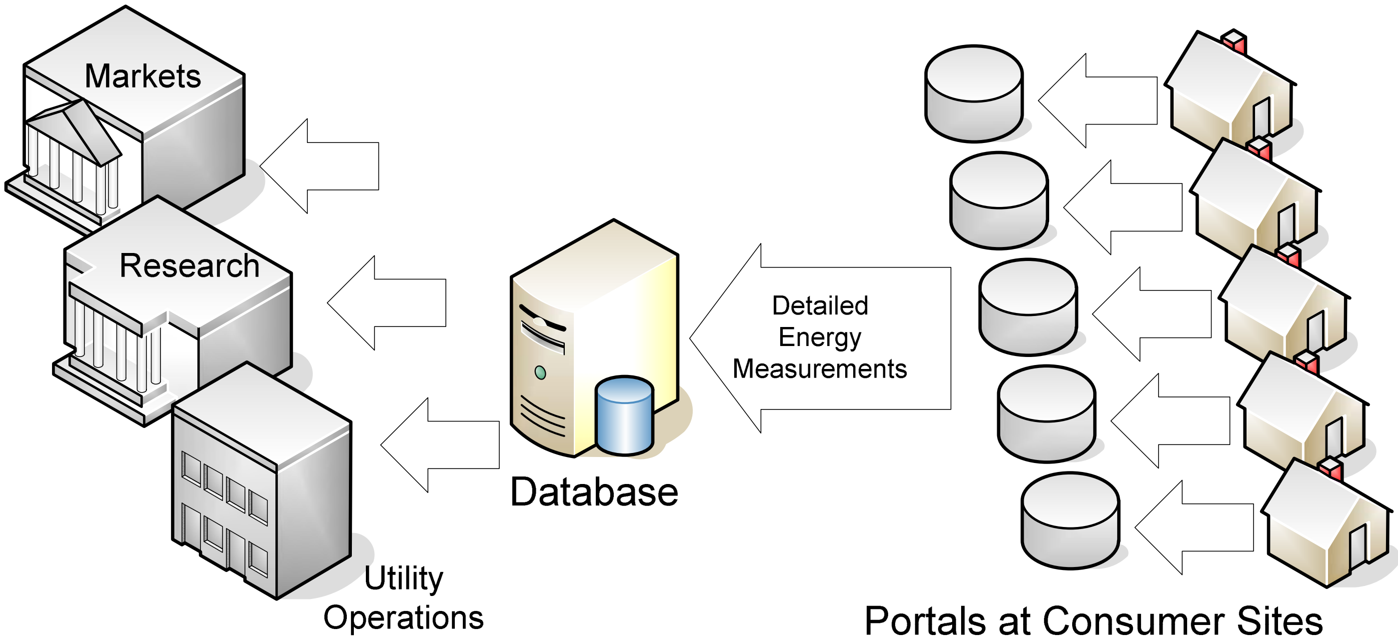
- Integrate with local Energy Management System
- Optimize energy use
- Compute energy efficiency
- Control distributed generation
- Coordinate load profiles between buildings
- Submit bids to energy markets

What could portals do?
Customer Management



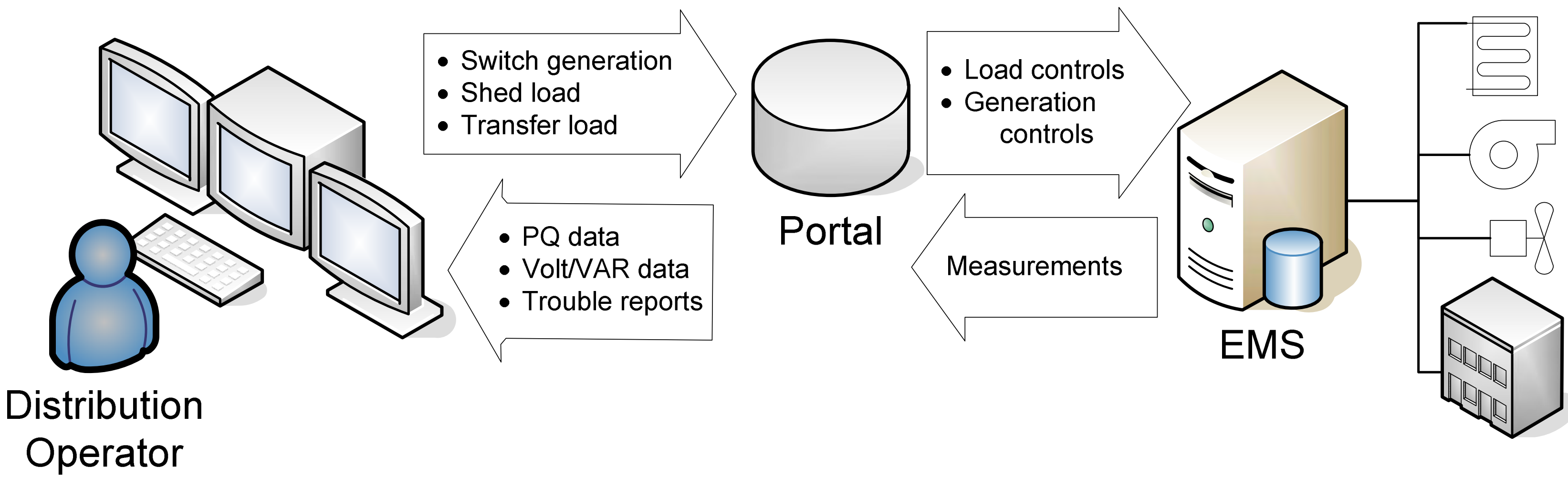
- Remotely connect or disconnect customers
- Detect tampering
- Detect theft of energy
- Limit maximum load in response to billing irregularity

What could portals do?
Widespread Distribution of Data



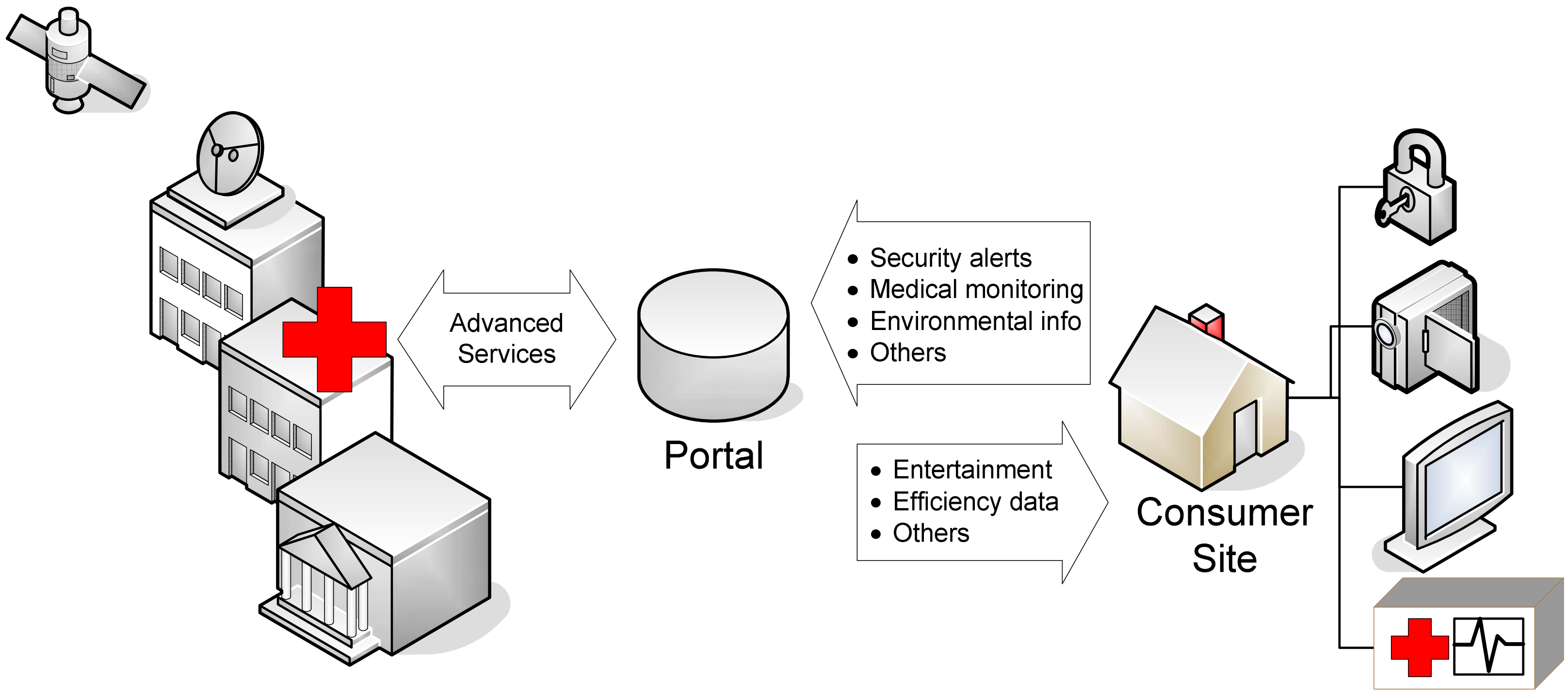
- Provide large volumes of accurate data for marketing, simulation, modeling, and predictive maintenance
- Aggregate data from multiple types of utilities
- Stagger load pickup in “black start” emergencies

What could portals do?
Advanced Distribution Operations



- Detect and isolate outages more quickly
- Shed load with finer control
- Use demand response customers as a “fast reserve”
- Monitor and optimize power quality more accurately
- Monitor and control distributed generation
- Minimize system losses

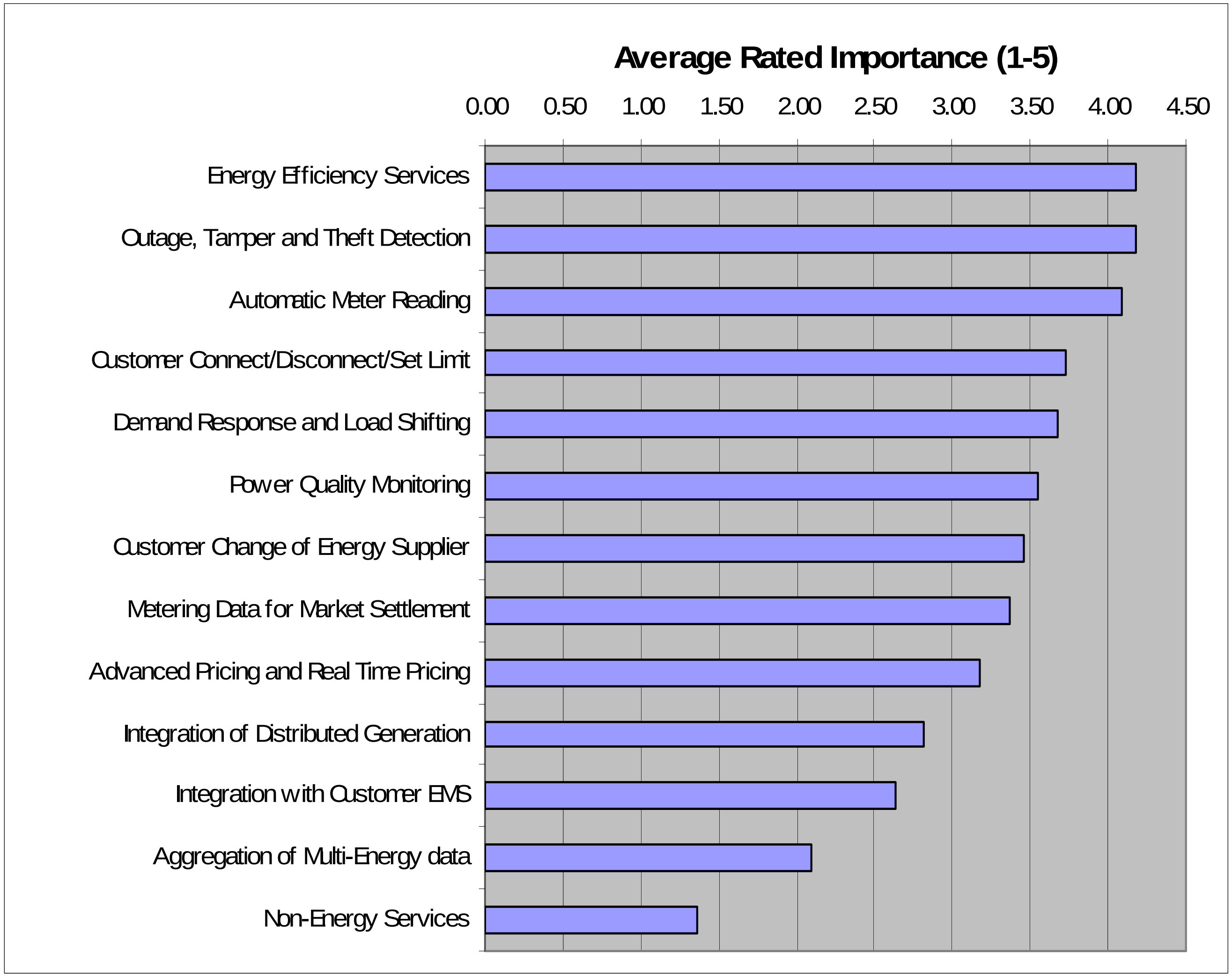
What could portals do?
Non-Energy Applications



Also:

- Weather forecasting
- Flooding and freezing alerts
- Air quality
- Optimize building heating and lighting

Which portal functions are most important?



- Feedback from IntelliGrid Consortium members

How Could Portals Make Money?

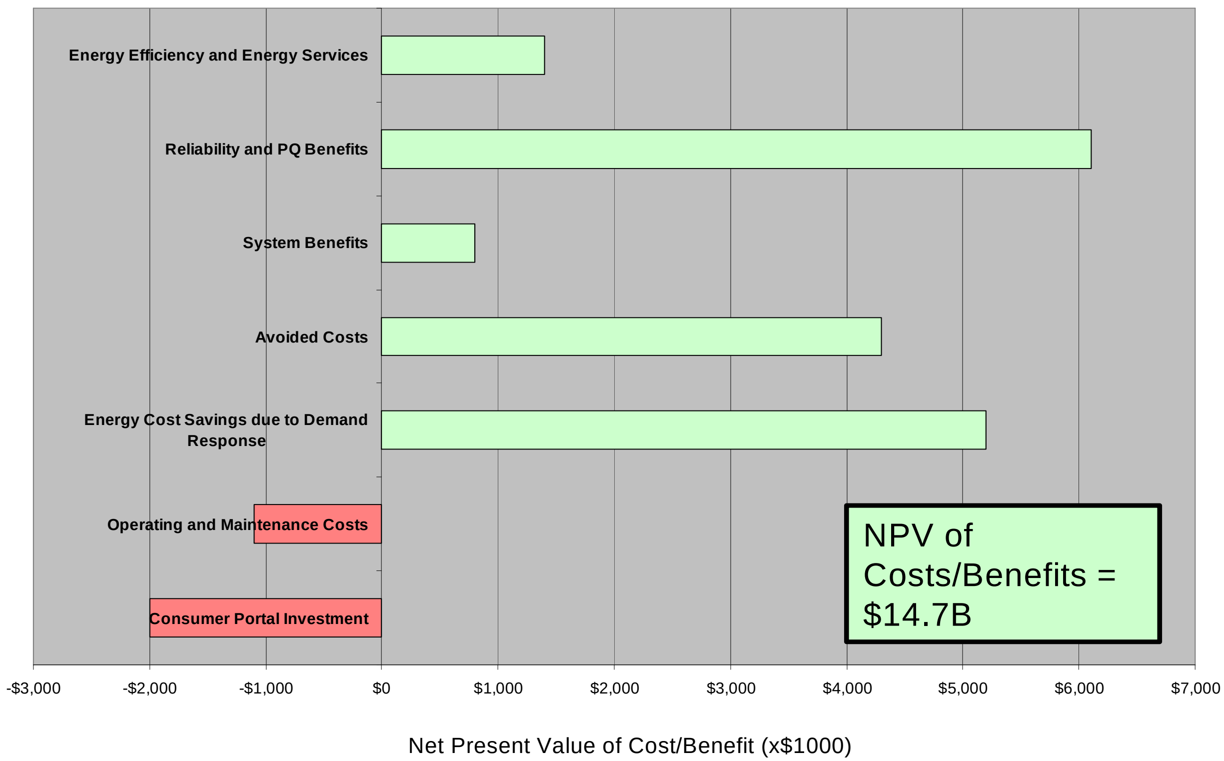
Benefits:

- Increased system efficiency, stability, and power quality
- Cumulative savings from demand response
- Avoided costs of incremental capital investment
- Recovered costs:
  - Theft detection
  - Fewer outages
- New income:
  - New value-added services
  - Participation in markets with better data

Barriers:

- Cost of equipment
  - Portal itself (unless embedded in other devices)
  - Peripherals, e.g. meters, thermostats, EMSs
- Cost of deploying networks
  - To the consumer site
  - Within the consumer site
- Cost of operation
  - Signing up customers
  - Technical support
  - Billing infrastructure

How could portals make money?
EPRI Study - 2004



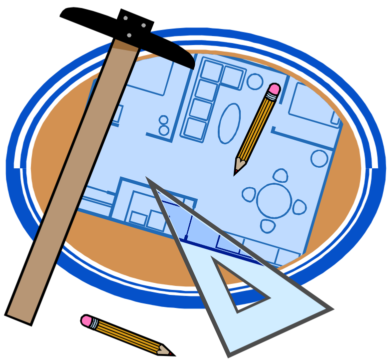
- 5-20 year assessment of California market
- 15% discount rate assumed
- $15B benefit to society AFTER investors have earned 15%!

How could portals make money?
Lessons Learned – from dozens of past attempts

- **The technology exists.**
  - No breakthroughs are necessary
- **Make it simple.**
  - Customer must be able to not participate
- **Standardize.**
  - Don't try to "lock in" customers to proprietary systems
  - Achieve economies of scale and reduce costs
- **Share the infrastructure.**
  - Use portal-like services from other industries
- **Build an architecture.**
  - Integrate the portal with the whole energy system
  - Don't create "islands of automation"
- **Don't strand assets.**
  - Make it easy and inexpensive to upgrade
  - The best applications may be yet to come
- **Share the benefits.**
  - Distribute the "societal benefits" to everyone

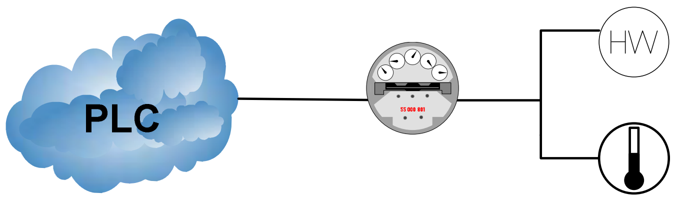
What could a portal look like?

- A consumer portal is an ***idea***, not a particular device!
- IntelliGrid is developing a ***reference design***
  - A standard "virtual appearance" for a portal
  - A clearly defined set of interfaces
  - May be incorporated into a variety of devices
  - May be ***distributed*** among several devices
- The physical device(s) may vary, but the virtual device ***must be standardized*** to ensure
  - Interoperability between vendors
  - Reduction in cost due to economies of scale
- Some vendors already provide portal-like devices, but they are ***not standard*** and ***not interoperable***.

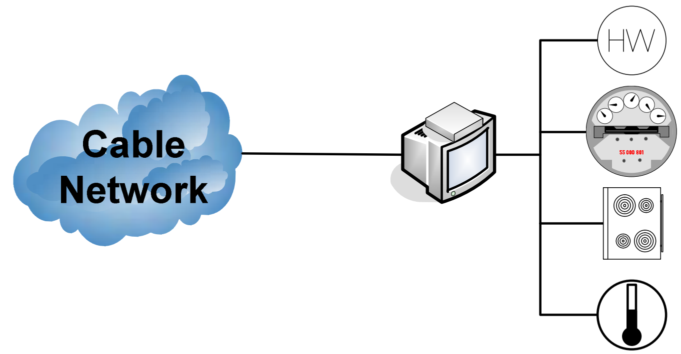


What could a portal look like?

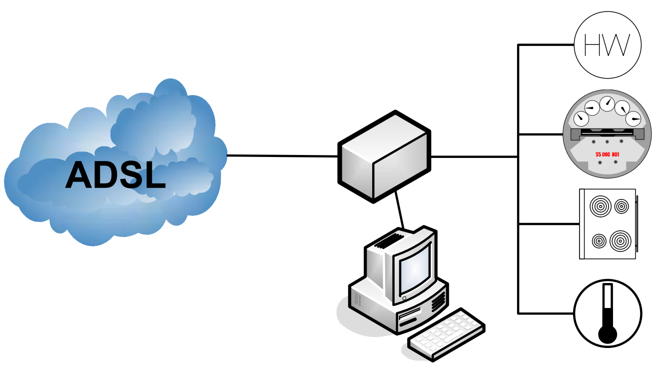
Some Options:



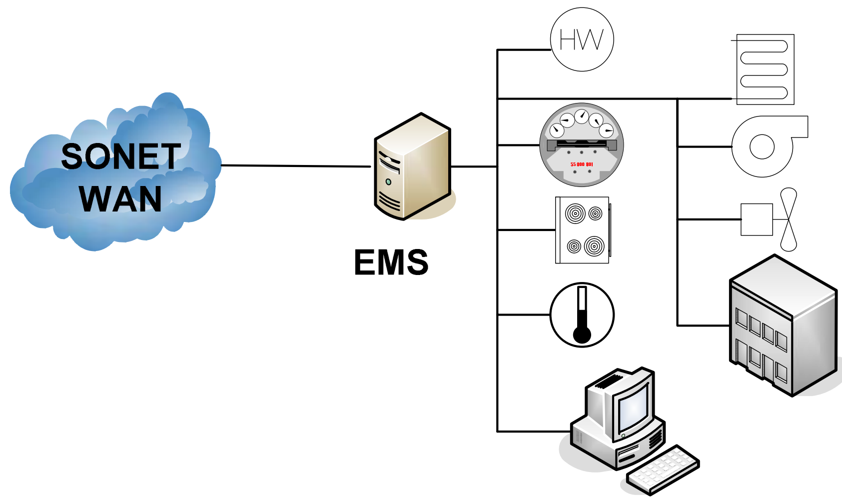
Portal in a meter



Portal in a set-top box



Portal in a stand-alone device or PC



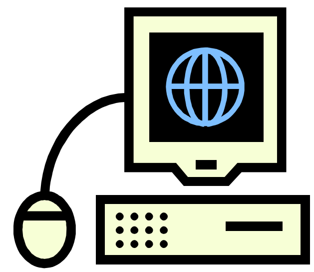
Portal in a local energy management system

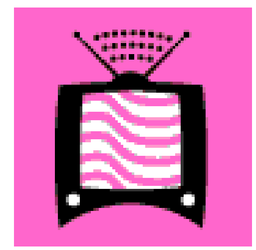
IntelliGrid℠

EPRI

What could a portal look like?
Possible User Interfaces

- A web page
  - Through Internet or directly
- A television interface
  - Similar to web interface
  - Through a set-top box
- A simple control panel
  - Colors to indicate tariffs
  - Buttons to control responses
- A single light
  - To indicate emergency curtailment
  - To indicate level of rates applied
- ...or others





What could a portal look like?
Characteristics

Every portal would have the SAME:

- Minimum data model
- Security scheme
- Upgrade mechanism
  - Tariffs
  - Configuration
  - Applications

The following things could be DIFFERENT:

- Innovative additions to the minimum data model
- In-building communications technology
- Wide-area network technology
- User Interface

Consumer Portal

- Questions before proceeding?

Background

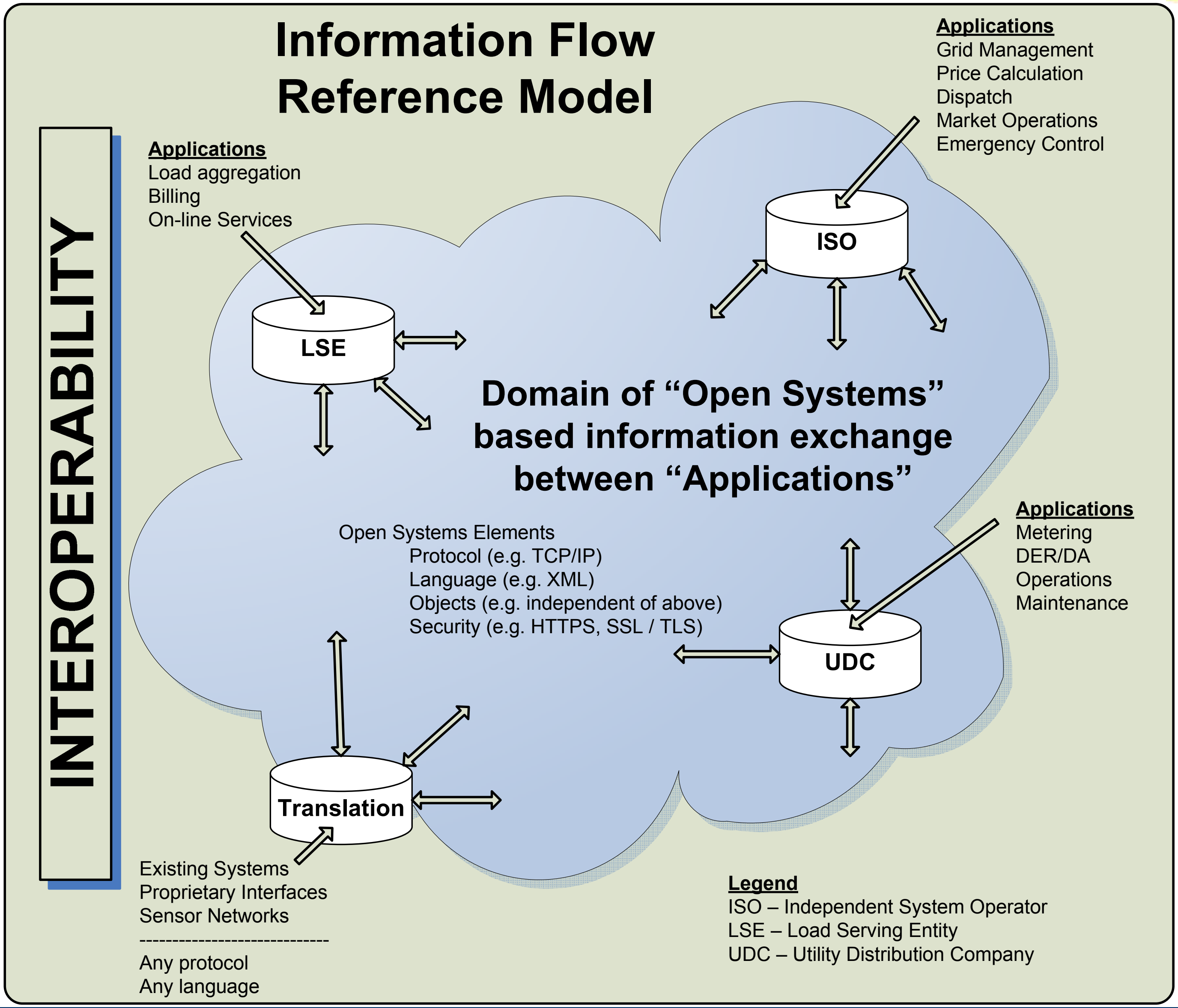
- The electricity crisis of 2000/2001 had many contributing factors
  - Market power (Enron, et al)
  - Aging fossil fuel plants (pollution)
  - Flaws in deregulation (AB 1890)
  - Disconnect between wholesale and retail prices
- However, most agree that one mitigating factor was missing

DEMAND RESPONSE

CEC Policy & Programs

- Under the leadership of Commissioner Rosenfeld, the CEC along with the CPUC, CPA, and the State's 3 major IOU's embarked upon a path to encourage DR through "price-responsive" load
- In support of this CEC policy and program, PIER initiated a DR Program to perform related R&D
- Consultant Report: "A Strawman Reference Design for Demand Response Information Exchange" - http://ciee.ucop.edu/dretd/

Back of the Napkin Concept



CALIFORNIA ENERGY COMMISSION

Characteristics of Infrastructure

- **Shareability** - Common resources offer economies of scale, minimize duplicative efforts, and if appropriately organized encourage the introduction of competing innovative solutions.
- **Ubiquity** - All potential users can readily take advantage of the infrastructure and what it provides.
- **Integrity** - The infrastructure operates at such a high level of manageability and reliability that it is often noticeable only when it ceases to function effectively.
- **Ease of use** - There are logical and consistent (preferably intuitive) rules and procedures for the infrastructure's use.

Characteristics of Infrastructure

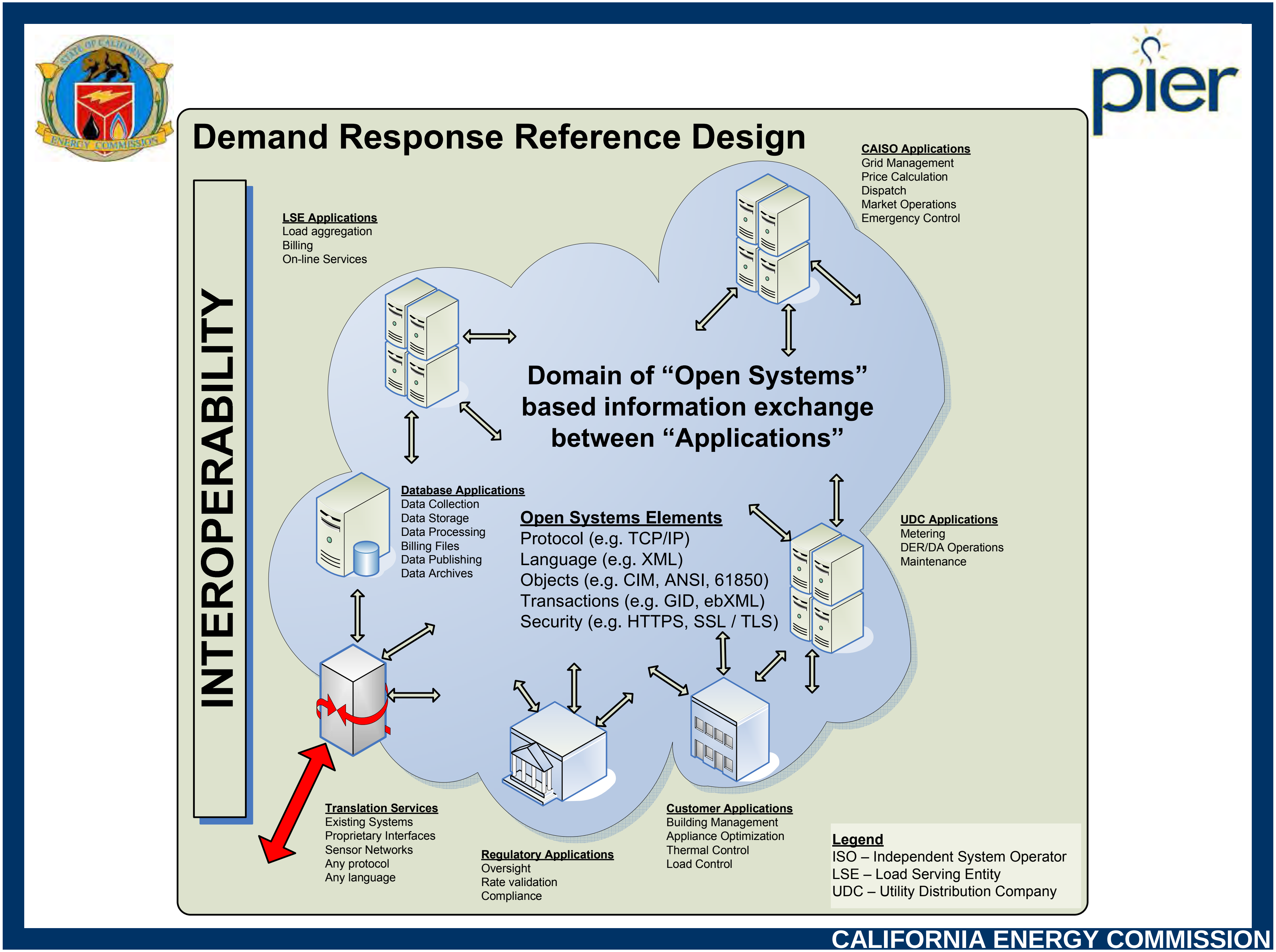
- **Cost effectiveness** - The value provided must be consistent with cost or the infrastructure simply will not be built or sustained.
- **Standards** - The basic elements of the infrastructure and the ways in which they interrelate are clearly defined and stable over time.
- **Openness** - The public infrastructure is available to all people on a nondiscriminatory basis.
- **Security** - The infrastructure must be protected against unauthorized access, interference from normal operation, and facilitate implementing information privacy policy

Demand Response Infrastructure: Principles and Goals

- The DRI must provide a set of interfaces, transactions and services to support current and envisioned demand response functions.
- The DRI must serve all constituents.
- The DRI must promote the principles of free enterprise.
- The DRI must protect the rights of users and stakeholders.
- The DRI must promote interoperability and open standards.

Strawman Reference Design

- Zones of information exchange
  - Inside is a domain of open systems information exchange
  - Outside is a domain of existing and proprietary devices and systems
- Between the two exists a defined set of interfaces
- The reference design is the set of implementing standards and technologies


Demand Response Reference Design
INTEROPERABILITY
CAISO Applications
Grid Management
Price Calculation
Dispatch
Market Operations
Emergency Control
LSE Applications
Load aggregation
Billing
On-line Services
Domain of "Open Systems" based information exchange between "Applications"
Database Applications
Data Collection
Data Storage
Data Processing
Billing Files
Data Publishing
Data Archives
Open Systems Elements
Protocol (e.g. TCP/IP)
Language (e.g. XML)
Objects (e.g. CIM, ANSI, 61850)
Transactions (e.g. GID, ebXML)
Security (e.g. HTTPS, SSL / TLS)
UDC Applications
Metering
DER/DA Operations
Maintenance
Translation Services
Existing Systems
Proprietary Interfaces
Sensor Networks
Any protocol
Any language
Regulatory Applications
Oversight
Rate validation
Compliance
Customer Applications
Building Management
Appliance Optimization
Thermal Control
Load Control
Legend
ISO – Independent System Operator
LSE – Load Serving Entity
UDC – Utility Distribution Company
CALIFORNIA ENERGY COMMISSION

CEC Reference Design

- Questions before proceeding?

SMART METERING CANADA

Agenda

- Context Setting
  - EPRI Consumer Portal Project Overview
  - California Influence – AMI Reference Design
- **Industry Response**
  - **OpenAMI Overview**
  - **UtilityAMI Overview**
- OpenHAN
- Security

OpenAMI Overview

- Formed in January 2005 in response to suggestion by the CEC PIER program as an outcome of publication of reference design report
- Hosted as a child entity under the UCA International Users Group
- OpenAMI accepted CEC reference design document as a starting point

SMART METERING CANADA

Why OpenAMI in UCA-IUG?

- Mission is to support open utility communications in general
- Strong connection to IEC and IEEE
  - Fast track to international standard
  - Option open for other standards orgs
- Large existing vendor participation
- Board members willing to sponsor it
- Later true for UtilityAMI and others

SMART METERING CANADA

OpenAMI Accomplishments

- Vendors agreed to open systems principles
- Adopted & expanded the DR reference design
- Developed initial list of AMI use cases
- Used as starting point by Southern California Edison
- Ratified SCE’s use cases
- Began discussions on standard comms interface for meters

OpenAMI Task Force

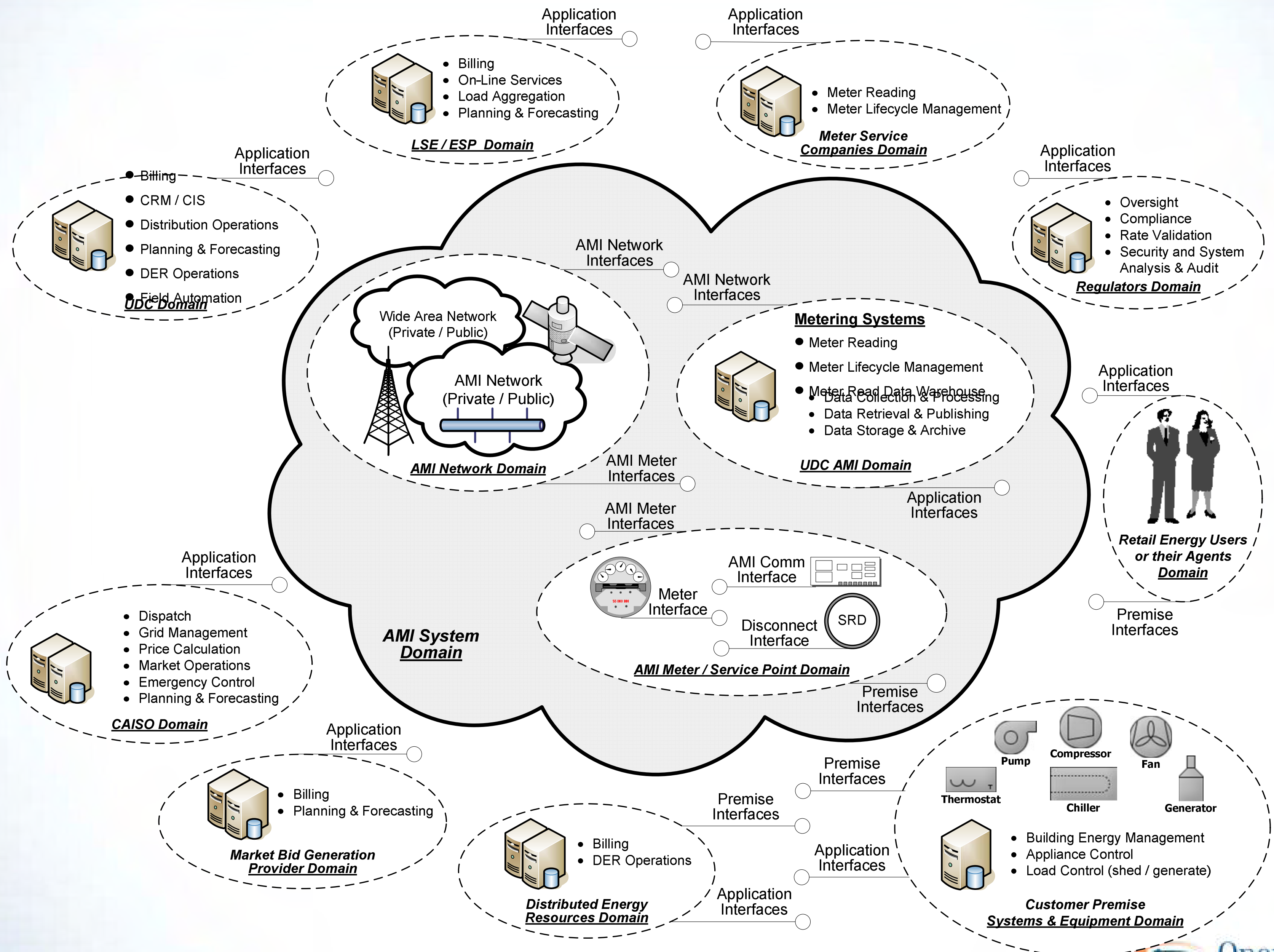
Mission Statement

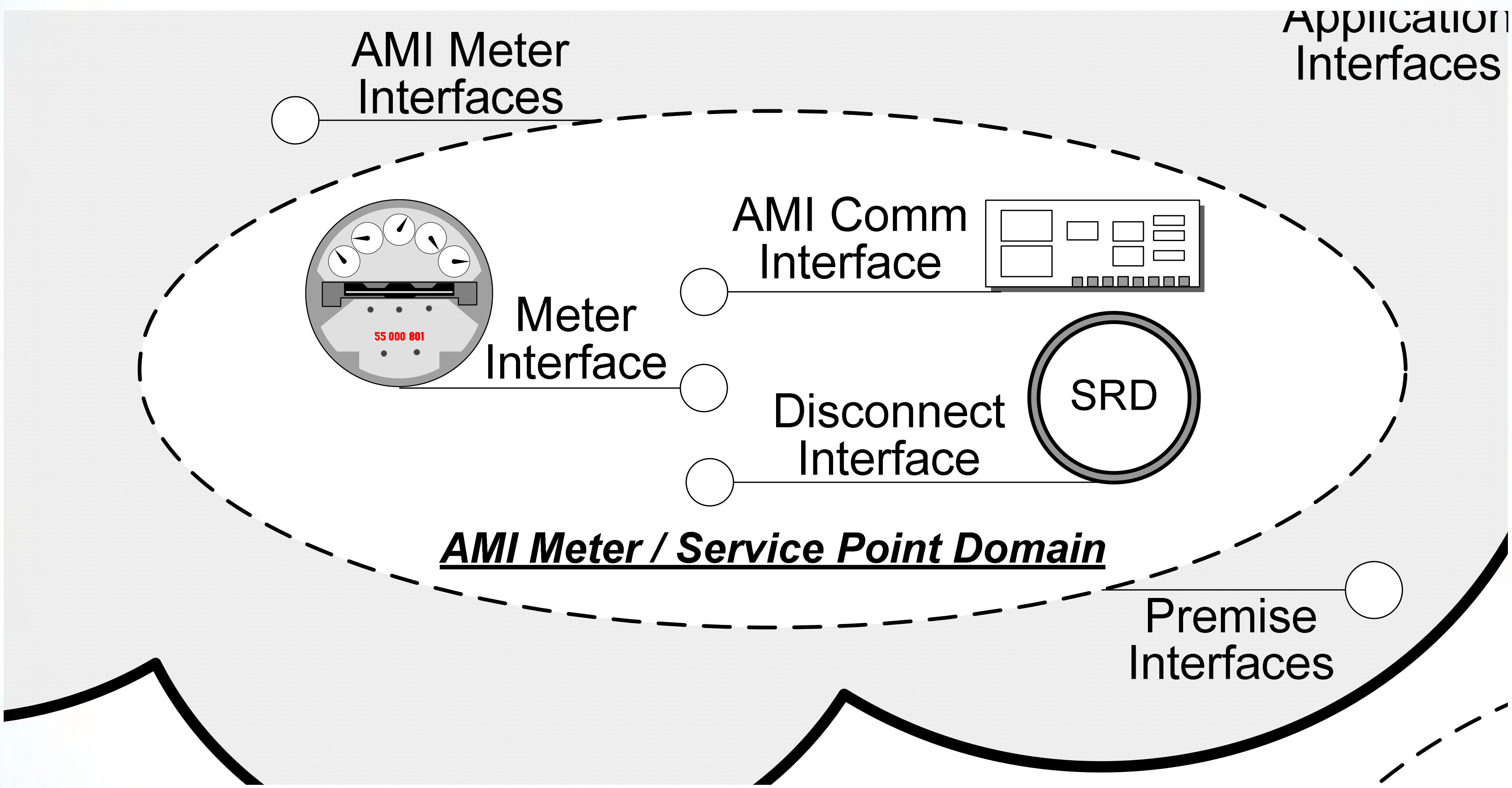
- Foster enhanced functionality, lower costs and rapid market adoption of Advanced Metering and Demand Response solutions through the development of an open standards-based reference design & data model

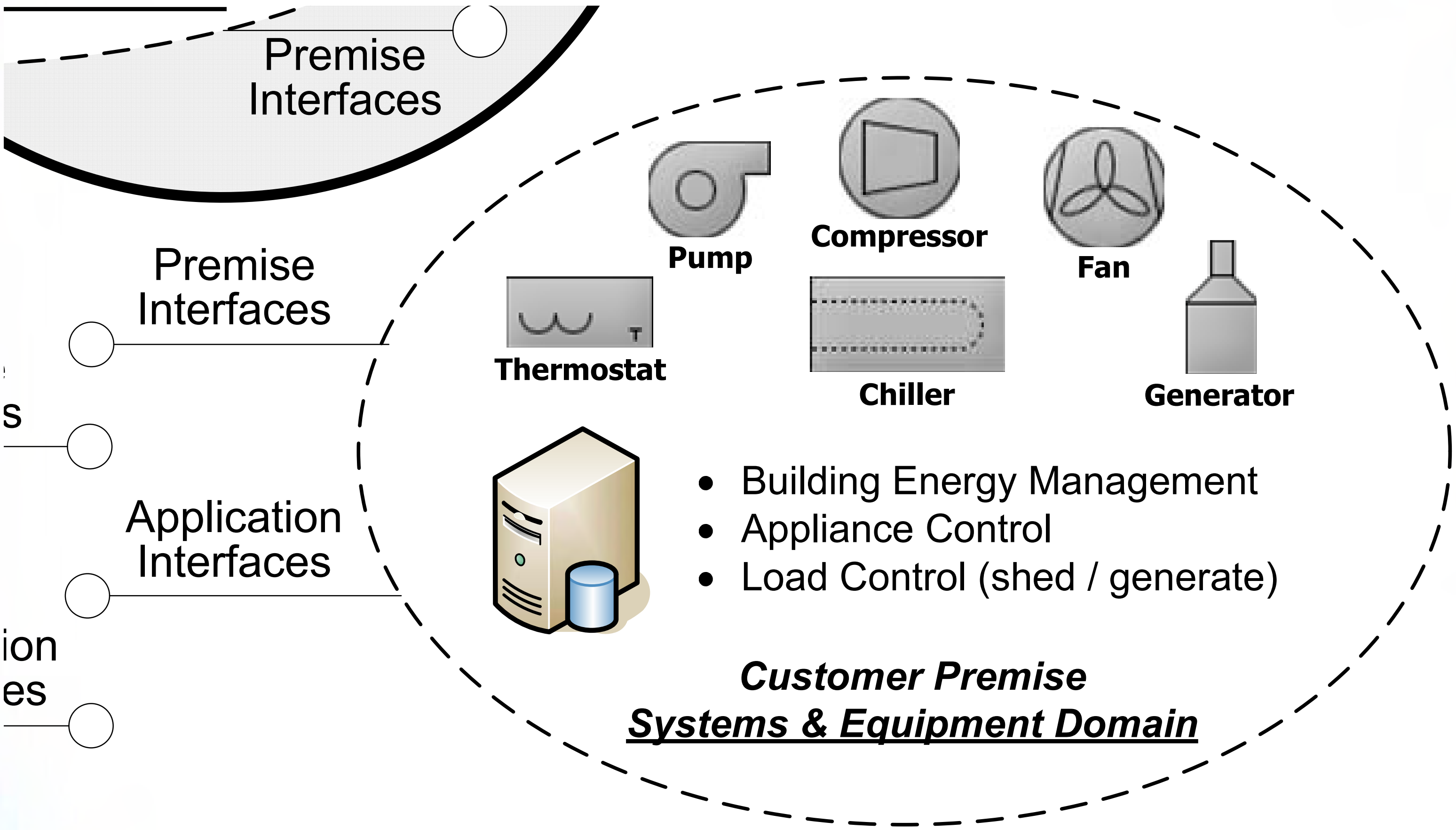
Objectives

- Facilitate the broad adoption of advanced metering and demand response
- Define what 'open standards' means for advanced metering and demand response
- Diminish technical and functional risk concerns for utilities, regulators and rate-payers
- Empower consumers with tools to better understand and manage their energy use
- Foster industry innovation, efficiency and lower cost solutions

OpenAMI Domains (based on CEC Reference Design)



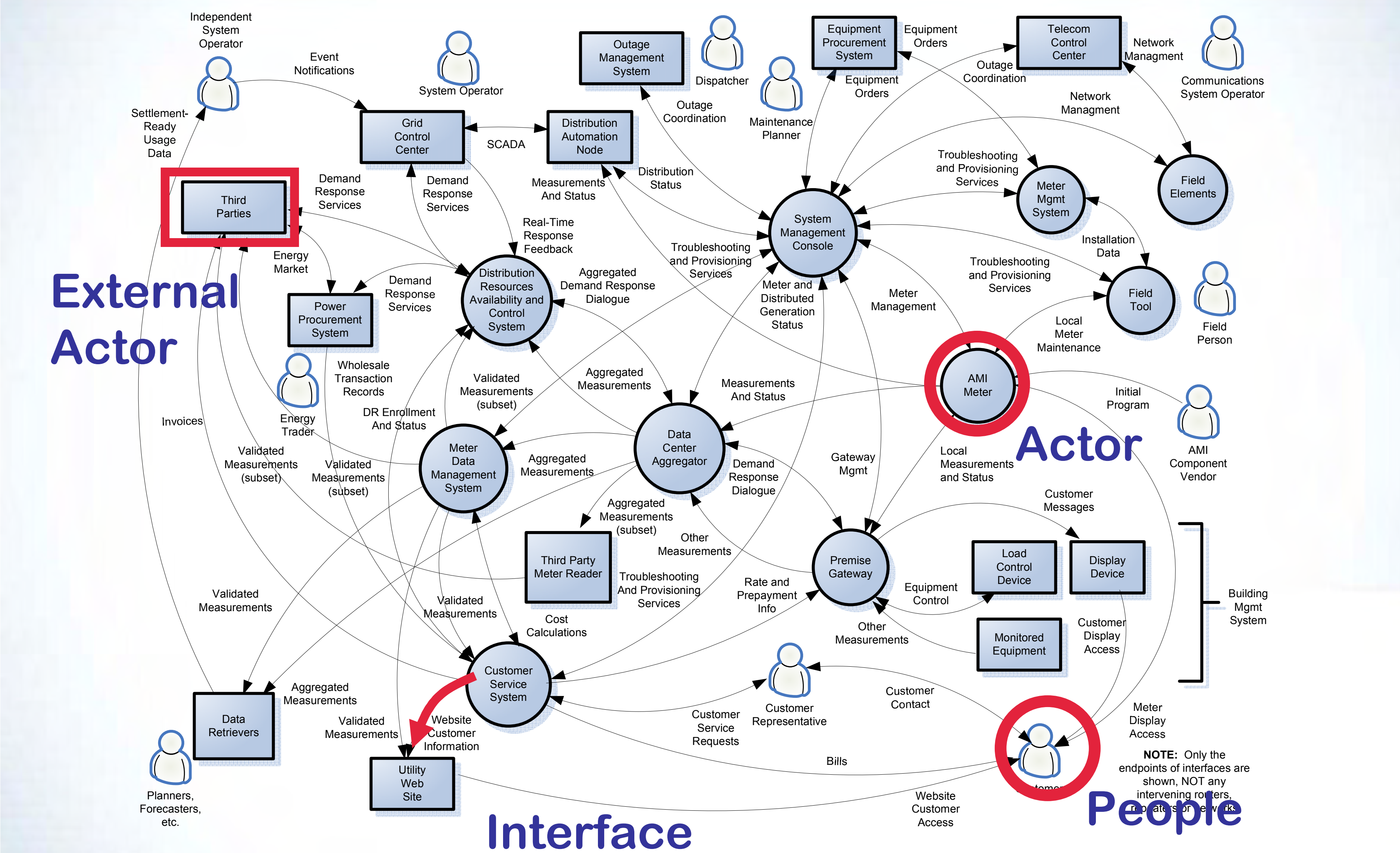

AMI Meter
Interfaces
Application
Interfaces
AMI Comm
Interface
55 000 801
Meter
Interface
SRD
Disconnect
Interface
AMI Meter / Service Point Domain
Premise
Interfaces


Premise Interfaces
Premise Interfaces
s
Application Interfaces
ion
es
Pump
Compressor
Fan
Thermostat
Chiller
Generator
• Building Energy Management
• Appliance Control
• Load Control (shed / generate)
Customer Premise
Systems & Equipment Domain

List of Original OpenAMI Use Cases

1. Multiple clients (hosts) read data automatically collected from customer premises
2. Consumers / Agents reduce demand in response to a pricing event
3. Consumers / Agent reads recent energy usage and cost at site
4. Distribution operator curtails customer load for grid management
5. Distribution operators detect tampering with customer site equipment
6. Distribution operators optimize network based on consumer metering data, and other data collected by the AMI System
7. AMI System recovers after power outage, communications or equipment failure
8. System manager provisions and configures the AMI System
9. Utility upgrades AMI System to address future requirements
10. Clients (Hosts) use AMI System to read data from multiple devices at customer premise
11. Lifecycle Management
12. Outage Detection, Management &Service Restoration
13. Billing Enquiry
14. Service Pre-Pay (or pay per use)

Southern California Edison AMI Data Flow Diagarm



OpenAMI

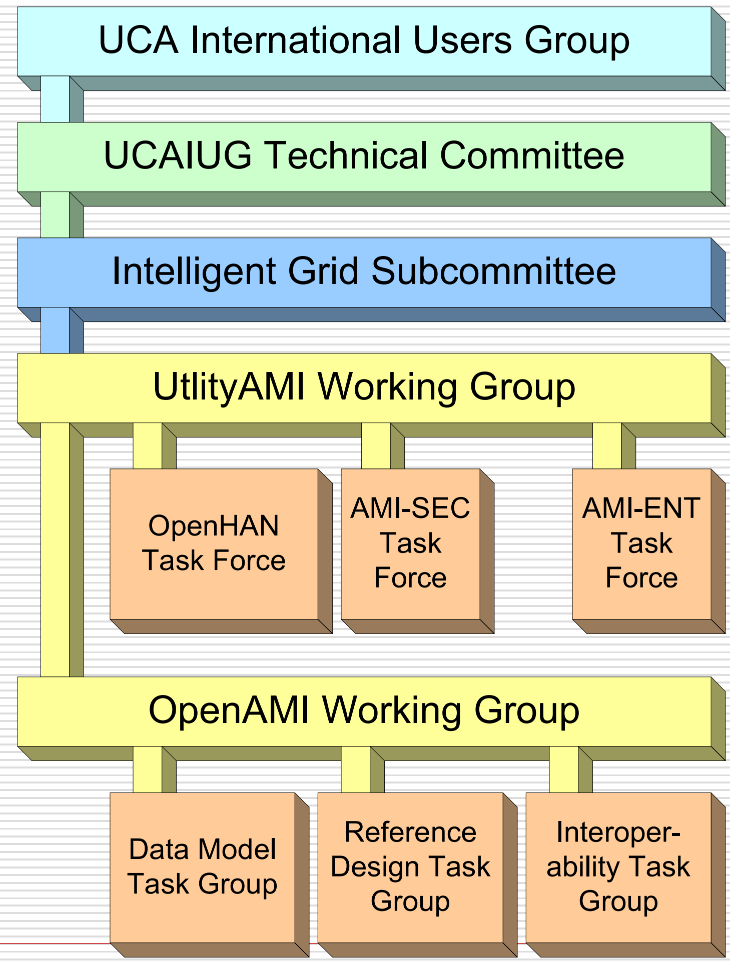
SMART METERING CANADA

OpenAMI Overview

- Questions before proceeding?

UtilityAMI Overview

- Formed November 2005
- Intended to address lack of utility guidance
- Need for requirements to be driven by entities who will buy AMI systems and their components - utilities



SMART METERING CANADA

UtilityAMI Tasks

1. Glossary and Common Language Framework
   - ✓ a) *A universal AMI glossary of terms and definitions*
   - ✓ b) *A framework for technology capability evaluation*
   - ✓ c) *A common, minimum requirements definition document*
2. Modular Meter Interface
3. Security
4. Consumer Interface
5. AMI Network Interface
6. Back Office Interface
7. Vendor database - online

SMART METERING CANADA

Glossary: Definition of AMI - 1

- An advanced metering infrastructure is a comprehensive, **integrated** collection of devices, networks, computer systems, protocols and organizational processes dedicated to **distributing highly accurate information** about customer electricity and / or gas usage **throughout the utility** and back to the customers themselves.

Glossary: Definition of AMI - 2

- Such an infrastructure is considered "advanced" because it not only gathers customer data **automatically** but does so **securely**, **reliably**, and in a **timely** fashion while adhering to published, **open standards** and permitting simple, **automated upgrading** and expansion.

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Glossary: Definition of AMI - 3

- A well-deployed advanced metering infrastructure enables a **variety of utility applications** to be performed **more accurately and efficiently** including time-differentiated tariffs, demand response, outage detection, theft detection, network optimization, and market operations.

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Common Requirements Document

- A short, **easily reviewable summary** of what UtilityAMI members consider important for an Advanced Metering Infrastructure.
- The **currently foreseeable requirements** for AMI systems.
- AMI vendors should consider taking the information in this document into account when designing or developing AMI Systems or components
- Each utility will be making its own independent decision on infrastructure and technology; consequently specific requirements will **vary from utility to utility**.
- Document intended to provide to vendors some **general guidelines** as to currently desired AMI system functionality.

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The UtilityAMI Requirements

1) Standard Communication Board Interface
2) **Standard Data Model**
3) **Security**
4) **Two-Way Communications**
5) Remote Download
6) Time-of-Use Metering
7) Bi-Directional and Net Metering
8) Long-Term Data Storage
9) Remote Disconnect
10) Network Management
11) Self-healing Network
12) **Home Area Network Gateway**
13) Multiple Clients
14) Power Quality Measurement
15) Tamper and Theft Detection
16) Outage Detection
17) Scalability
18) Self locating

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Requirements Voting Results

- 10 YES votes out of 10 voting – unanimous!
- The utilities voting represent more than 20 million meters in North America and nearly 60 million meters worldwide.

1. American Electric Power (AEP)
2. Con Edison
3. Duke Energy
4. Electric Power Research Institute (EPRI)
5. Electricité de France (EDF)
6. First Energy
7. Hawai'ian Electric Company (HECO)
8. Keyspan Energy
9. Sempra Energy (SDG&E)
10. Southern California Edison (SCE)

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UtilityAMI Tasks - Status

1. Glossary and Common Language Framework
   - ✓ a) *A universal AMI glossary of terms and definitions*
   - ✓ b) *A framework for technology capability evaluation*
   - ✓ c) *A common, minimum requirements definition document*
2. Modular Meter Interface – Transferred to OpenAMI
3. Security – AMI-SEC Task Force
4. Consumer Interface – OpenHAN Task Force
5. AMI Network Interface – not yet started
6. Back Office Interface – AMI-Enterprise Task Force
7. Vendor database - online

Industry Response Overview

- Questions before proceeding?

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Agenda

- Context Setting
  - EPRI Consumer Portal Project Overview
  - California Influence – AMI Reference Design
- Industry Response
  - OpenAMI Overview
  - UtilityAMI Overview
- **OpenHAN**
- AMI-SEC

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Leading HAN Technologies - 1

- WiFi
  - Standards based, multi-channel, widespread application, industry association
  - Complex configuration, no inherent mesh/range extension
  - Transport only – no application layer application models
- ZigBee
  - Mesh network, robust, products available, industry association
  - Standards based, multi-channel, interference mitigation
  - Need well defined information models – work in progress

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Leading HAN Technologies - 2

- HomePlug PLC
  - Simple, robust, products exist, industry association
  - Was proprietary – alliance supported, moving toward standardization – IEEE P1901
  - Transport only – no application layer application models
  - Cannot reach thermostat without a gateway
- ZWave
  - Mesh network, robust, products available, industry association
  - Proprietary, single frequency (908.42 MHz), no agility mechanism
  - Need well defined information models – work in progress

Leading HAN Technologies - 3

- 6LoWPAN
  - IPv6 over Low Power Wireless Personal Area Networks
  - Carrying IPv6 over IEEE 802.15.4
  - Good addressing and security in theory, maybe not so much in practice.
  - Network layer to data link mapping, no application layer

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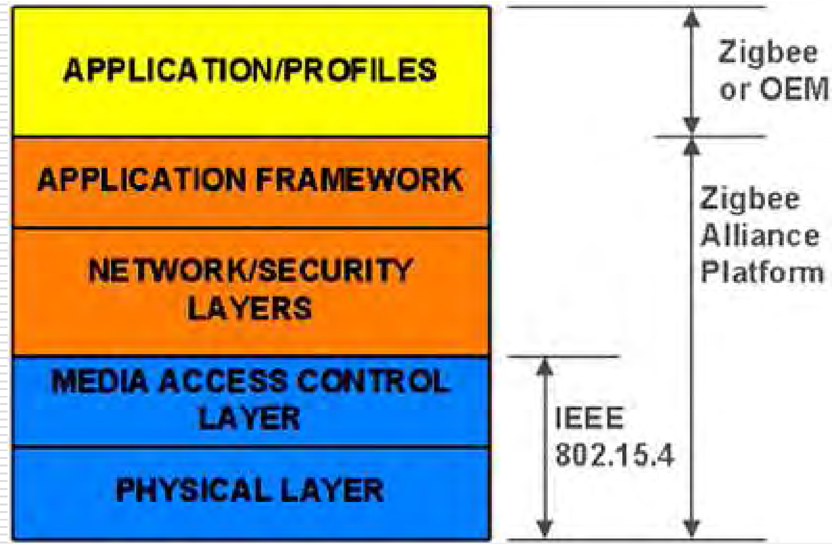
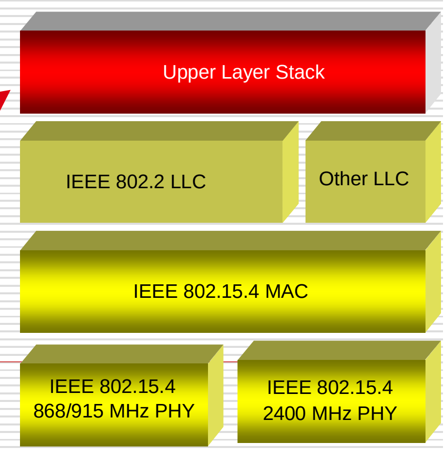
Technology Summary

- None have standard application layer models
- PLC ruled out as sole interface
- Need to reach thermostat and other devices not reachable by PLC (e.g. gas meter)
- All ISM band based devices subject to



- IEEE 802.15.4
  - MAC and PHY only

Metering Applications exist in the upper layer – control the network, metering and load control applications



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OpenHAN Task Force Scope

Develop the missing application layer:

- High level reference design/architecture
- Utility requirements
- Information models
- Security

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Stakeholders and Collaborators

- Utility driven
- Vendor input required
  - Hardware – network, devices
  - Associations – e.g. ZigBee, ZWave, Etc.
- Standards Groups

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Envisioned Deliverables

- HAN Principles and Framework
- HAN Use Cases
- HAN Requirements
- Device Models (or another TF)
- Security Model (of another TF)

UtilityAMI OpenHAN TF

Requirements Working Group

Specification Briefing

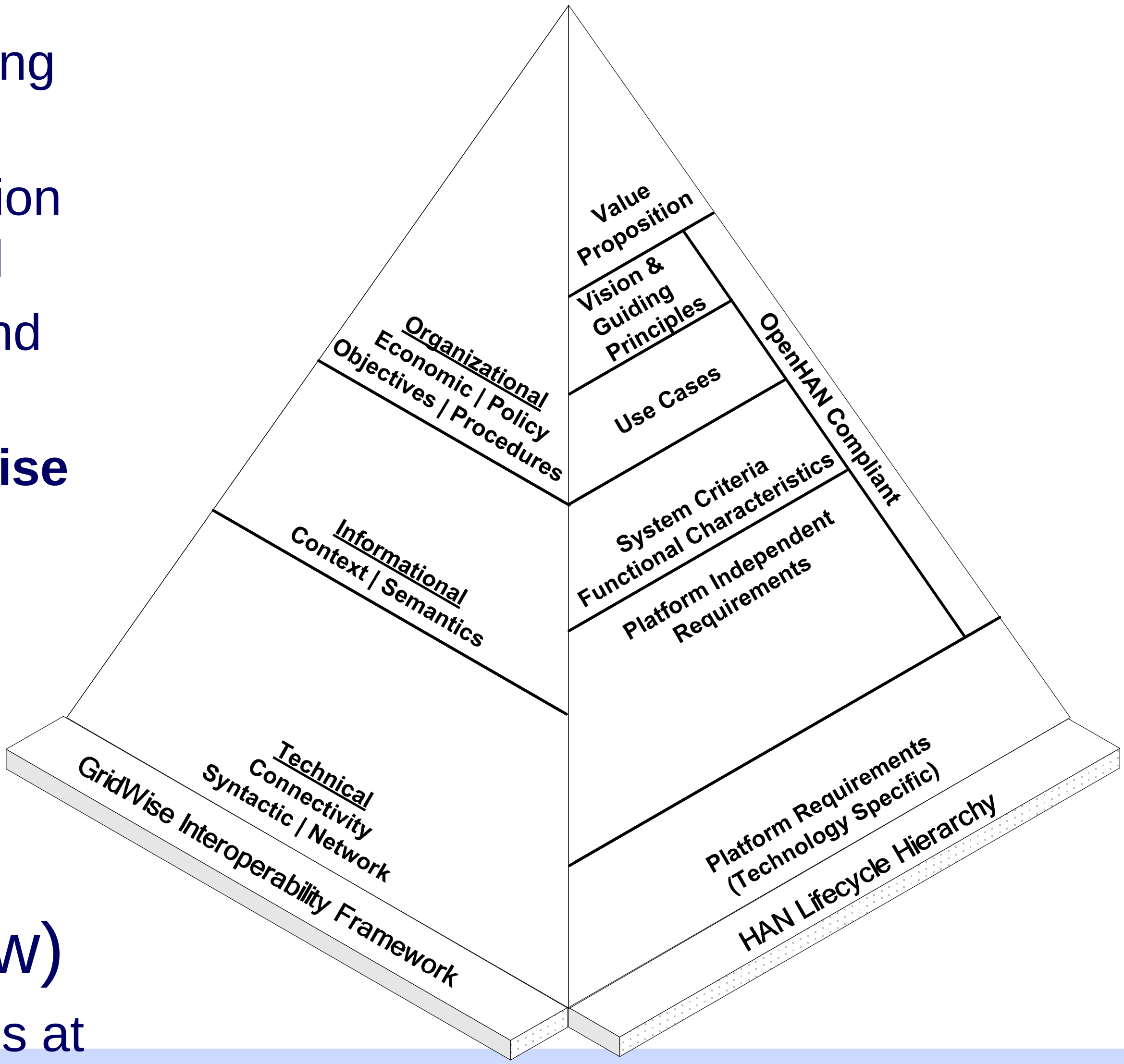
January 2008

OpenHAN Requirements Specification

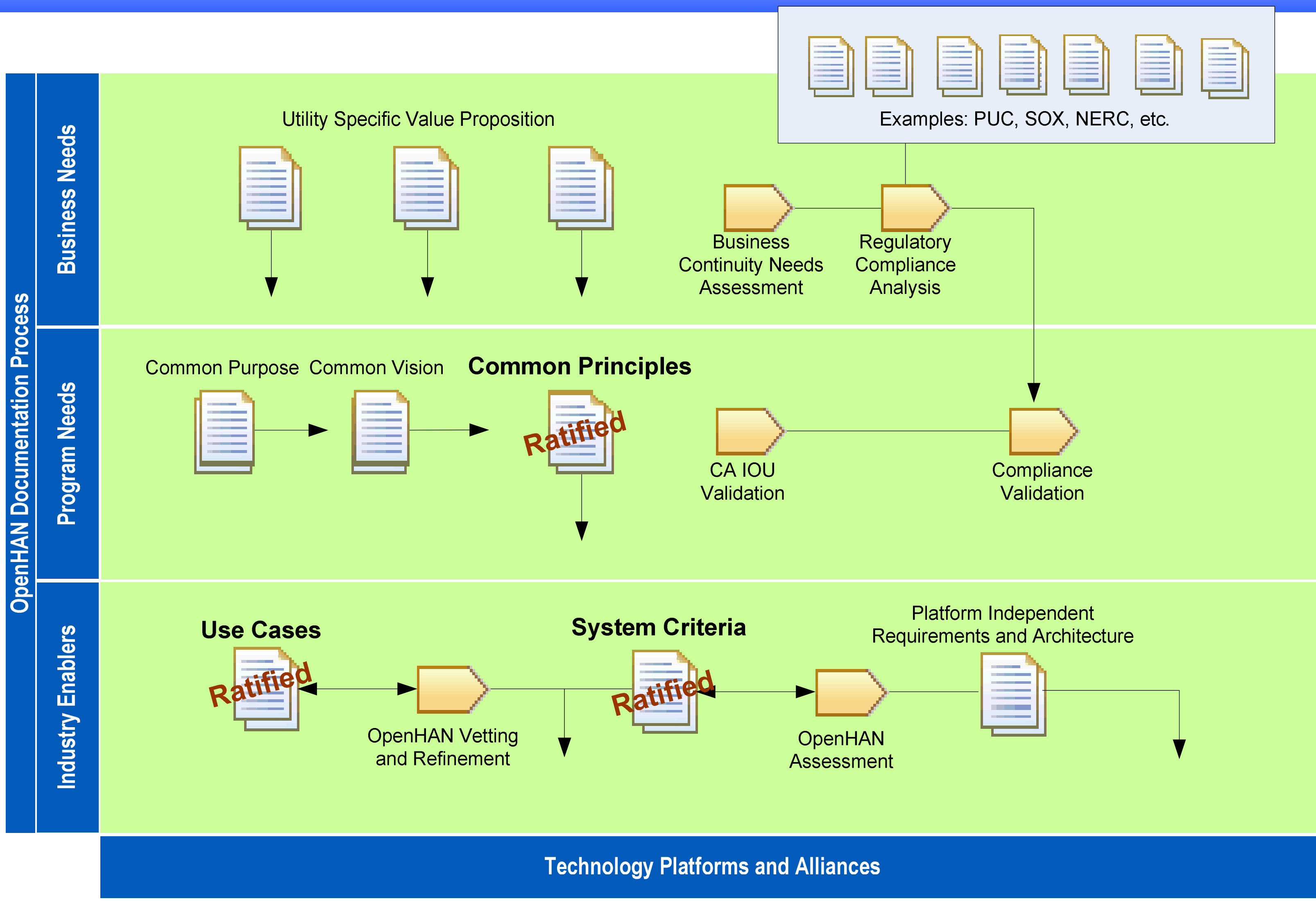
- Purpose:
  - Information sharing (level setting)
  - Validate approach
  - Drive technology implementations
  - Establish participation and responsibility
  - Describes utility's view of HAN
  - Establishes participation scope and scale
  - Intended audience:
    - Regulators – establish position, clarify roles and responsibility
    - OpenHAN – creates input for further system refinement (e.g., platform independent requirements, use cases)
    - Vendors – shows approach, motivation
  - Establishes a baseline
  - Time management: cuts down on vendor clarification meetings and phone calls

Utility HAN Framework

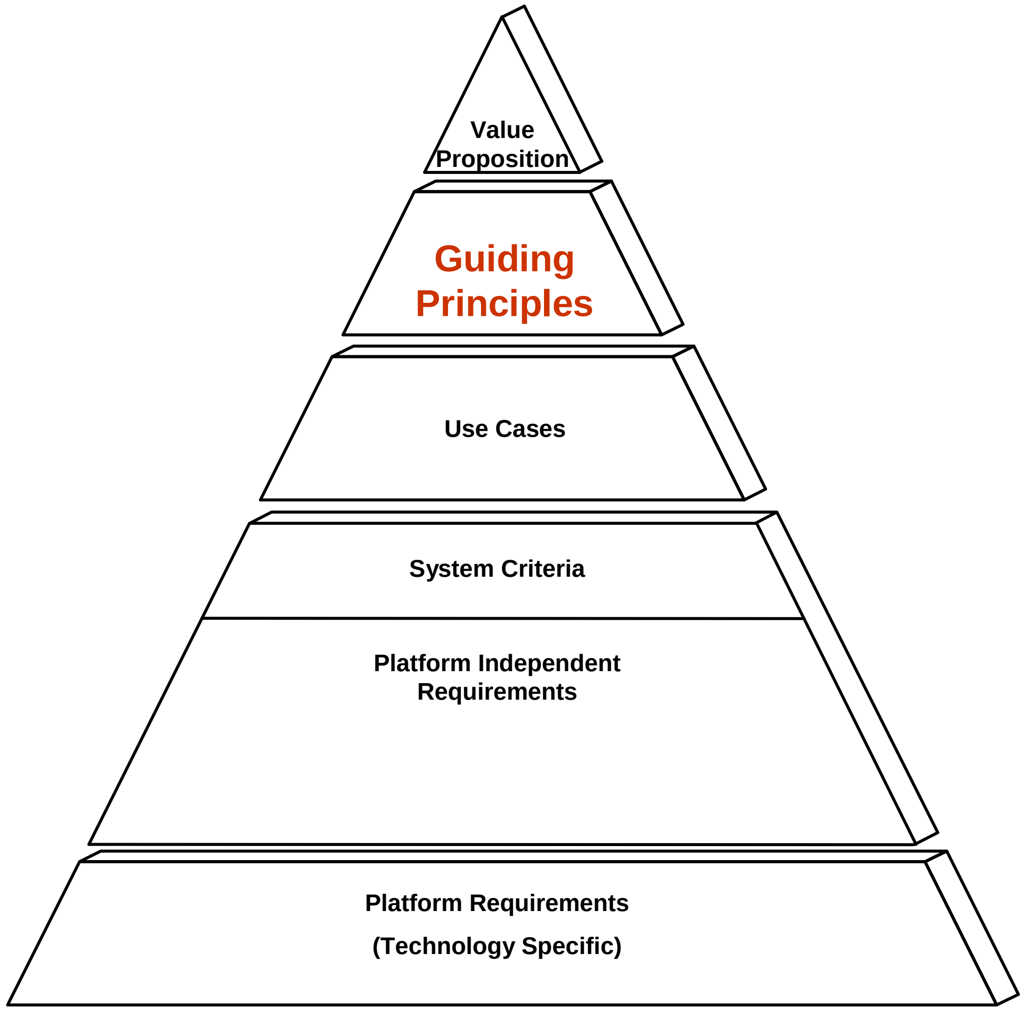
- Based on Strategic Planning and System Engineering
- Each level provides direction and context for lower level
- Delineates participation and accountability
- Can be mapped to **GridWise Architecture Framework** (Loosely coupled - Decomposition framework vs. organizational interoperability view)
- Stakeholder considerations at every level: regulators, consumers, utilities, vendors



Documentation Process (Ratified)



HAN Guiding Principles

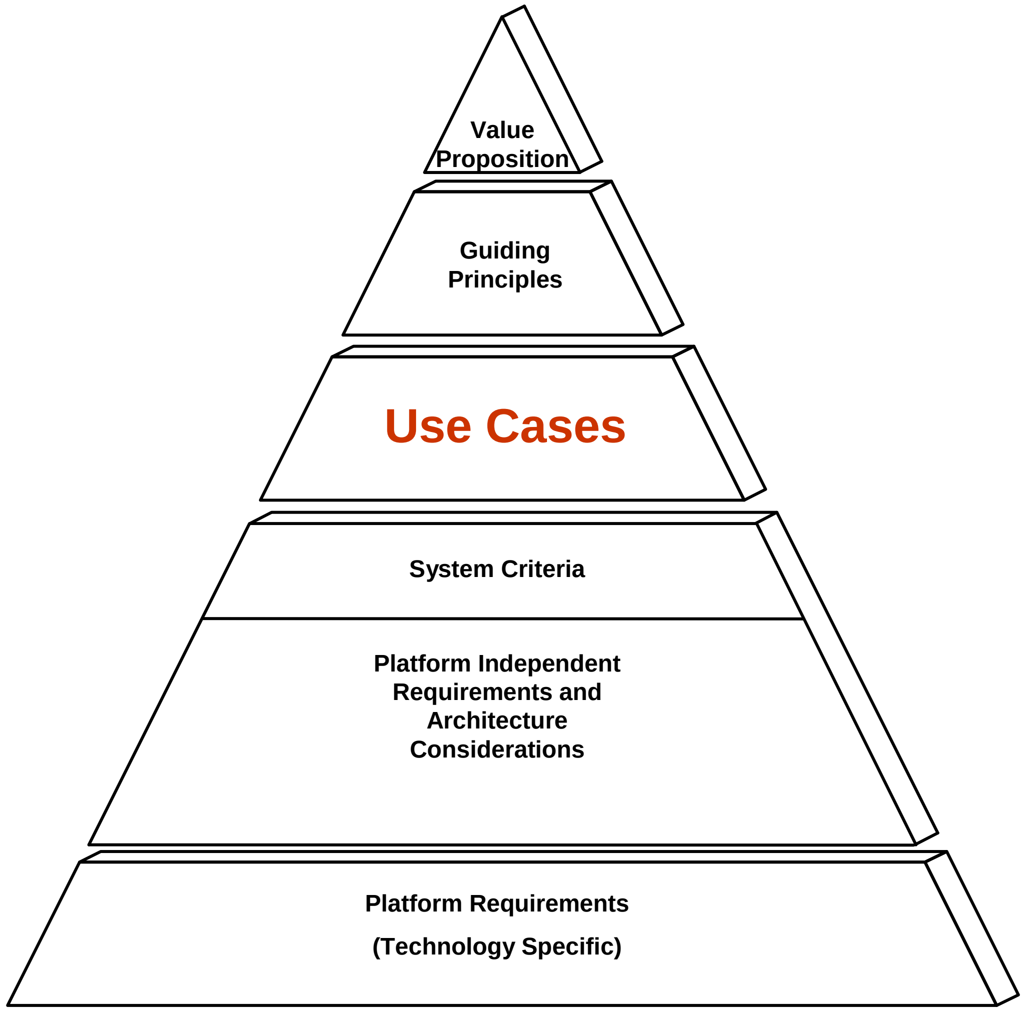


HAN Guiding Principles

Capabilities

- Supports a secure two way communication with the meter
- Supports load control integration
- Provides direct access to usage data
- Provides a growth platform for future products which leverage HAN and meter data
- Supports three types of communications: public price signaling, consumer specific signaling and control signaling
- Supports distributed generation and sub-metering

HAN Use Cases



Use Case Scope

- **Abstracted to highest level** for rapid adoption (i.e., more details to follow) note: previous work has been more detailed
- Concentrates on **Utility to HAN interactions**
- Device **ownership independent** (e.g., registration is the same whether or not the utility supplies the device)
- Interactions are based on **utility-relevant activities** only (Ignores other HAN activities within the premise – e.g., Home Automation)
- Required device functionality will be specified in subsequent phases (i.e., platform independent requirements)

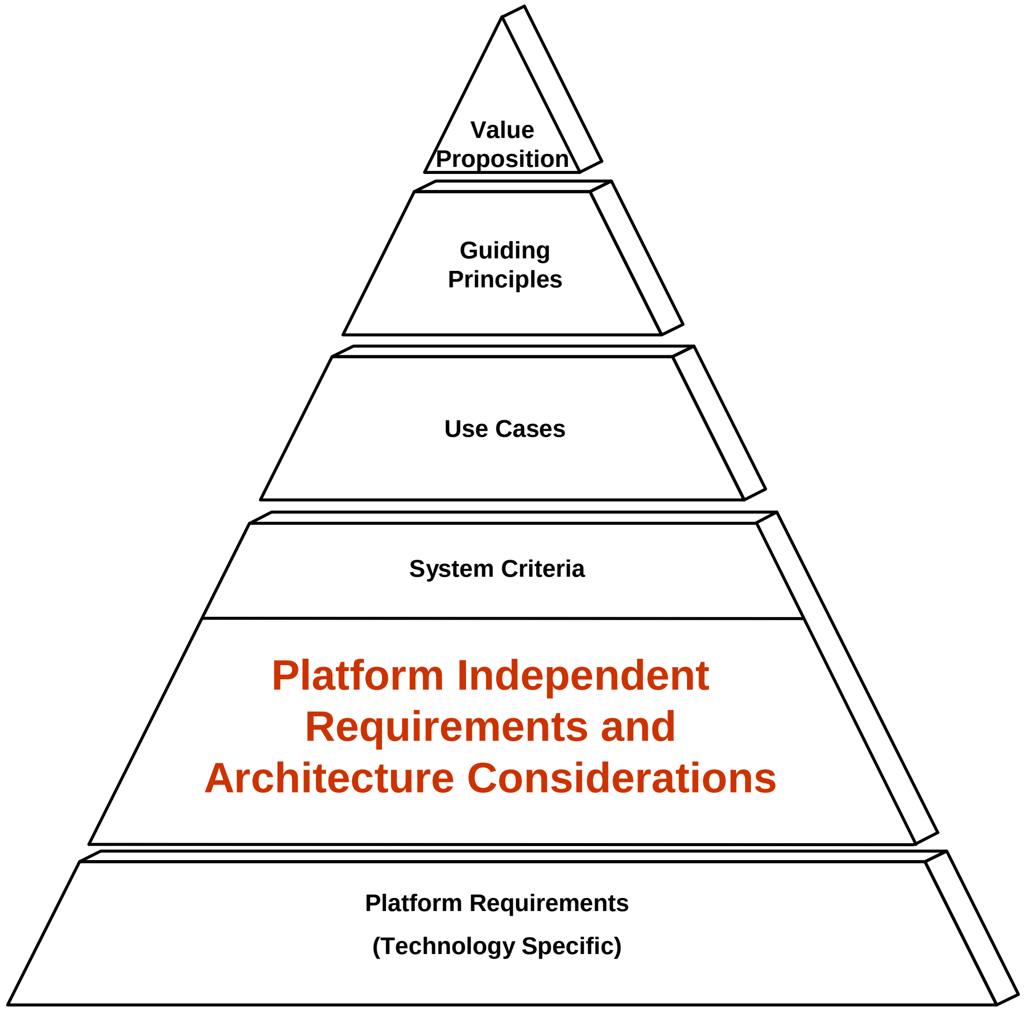
Use Case Organization

- System Management and Configuration
  - Depot Configuration
  - Installation and Provisioning
  - Utility Registration
  - Remote Diagnostics
  - Maintenance and Troubleshooting
- Load Control and Energy Management
  - Voluntary
  - Mandatory
  - Opt-out
- Energy Management System
- Energy Storage and Distribution
- User Information
- HAN Metering

Ratification of the Use Cases

- Ratified unanimously by the seven utilities in attendance 8/15/2007
  - AEP
  - Consumers Energy
  - Detroit Edison
  - EDF
  - PG&E
  - SCE
  - SDG&E
- Other utilities may ratify after review

Platform Independent Requirements



Requirements Overview

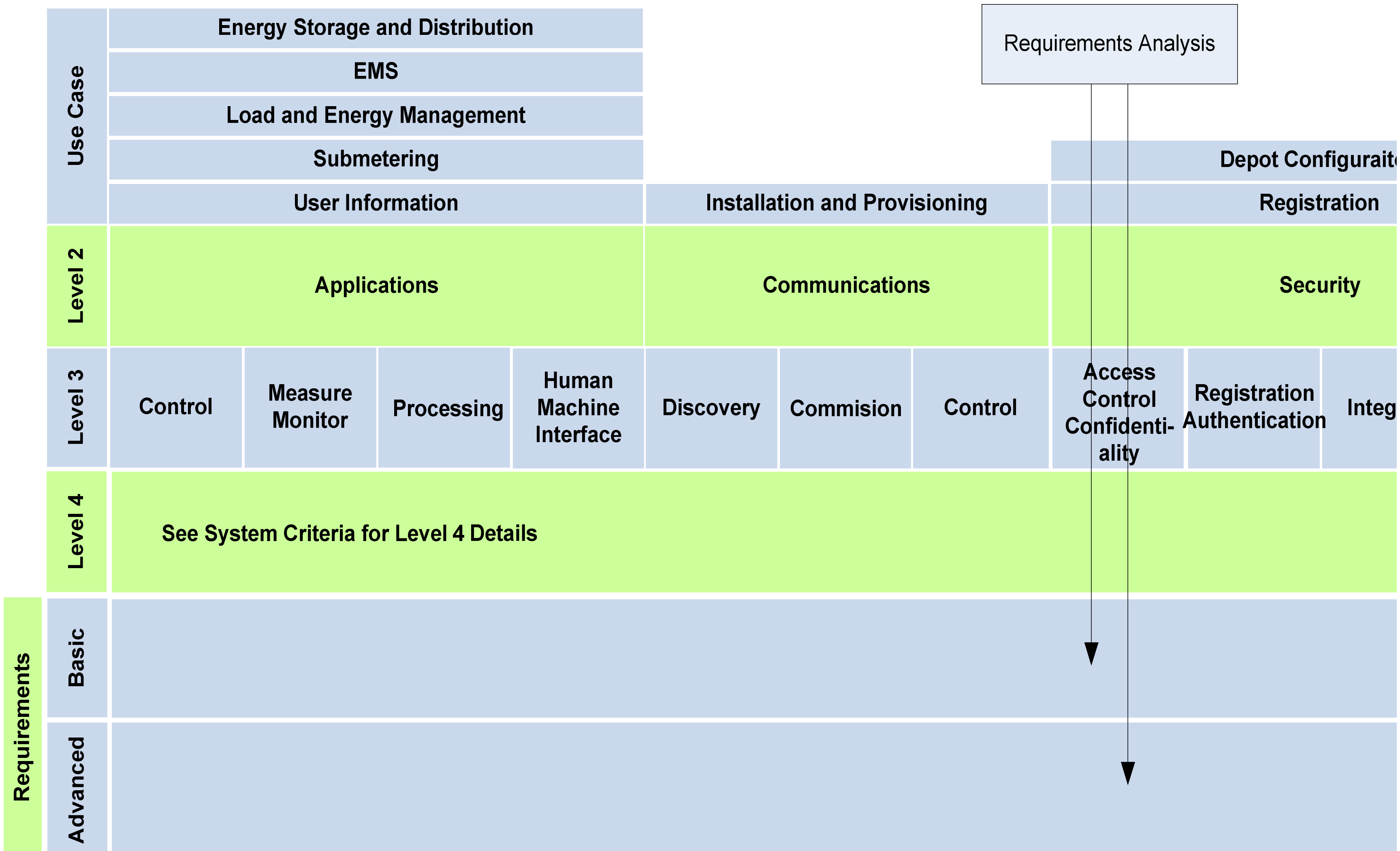
- Platform independent
- Applied via device mappings (Appendix)
- Special class for an AMI gateway (See Mappings)
- Two types of compliance
  - Technology/alliance – application and communication compliance (e.g., message structures)
  - Vendor/product – compliant with device mapping requirements

HAN Requirements Organization and System Criteria

Level 1	System*															
Level 2	Applications				Communications		Security				Performance			Operations Maintenance Logistics		
Level 3	Control	Measure Monitor	Processing	Human Machine Interface	Commision	Control	Access Control Confidenti-ality	Registration Authentication	Integrity	Account-ability	Availability	Reliability	Maintain-ability	Manufacture Distribute	Installation	Manage Maintain
Level 4	Direct Control	Distributed Generation	Energy Cost	User Input	Announce	Organize	Public	Initialization	Resistance	Audit	Scalability	Upgrade-ability	Quality	Pre-commision	Document	Alarm Logging
	Cycling Control	Submetering	Energy Consumption	User Output	Respond	Optimize	Private	Validation	Recovery	Non-Repudaition				Registration config	Support	Testing
	Limiting Control	Environment State	Energy Production		Identify	Prioritize	Utility	Correlation						Labeling		Reset
		Device State	Energy Optimization		Authenticate	Mitigation		Authorization						Purchasing		
			Energy Demand Reduction					Revocation								
			Environment Impact													
			Payment													

Platform Independent Requirements

Organizing Requirements from the Use Cases



Requirements Example

Context:
Applications that respond to control commands from the utility or authorized third parties. Commands typically tell a device to turn ON/OFF at configurable time intervals or thresholds or enter into an energy saving mode.

Requirements:

- App.Control.1 HAN Device shall accept control signals from the utility.
- App.Control.2 HAN Device shall respond to requests to cease operational state (e.g., open contact).
- App.Control.3 HAN Device shall respond to requests to resume operational state (e.g., close contact).
- App.Control.4 HAN Device shall acknowledge receipt of control signal.
- App.Control.5 HAN Device shall acknowledge execution of control request.
- App.Control.6 HAN Device shall acknowledge execution failure of request (i.e., exceptions).
- App.Control.7 HAN Device shall signal any consumer-initiated overrides.

Device Mappings

- Tool for applying the specification
- Device mappings are logical
- Actual Product offerings may include several logical devices
- Legend: Basic (B), Enhanced (E), Not Applicable (NA), Optional (O)
- Optional Requirements – suggestion to vendor to examine capability
- Logical Devices include:
  - Energy Services Interface
  - PCT
  - Display
  - EMS
  - Load Control
  - HAN Electric Meter
  - HAN Meter (non-electric)
  - Smart Appliance

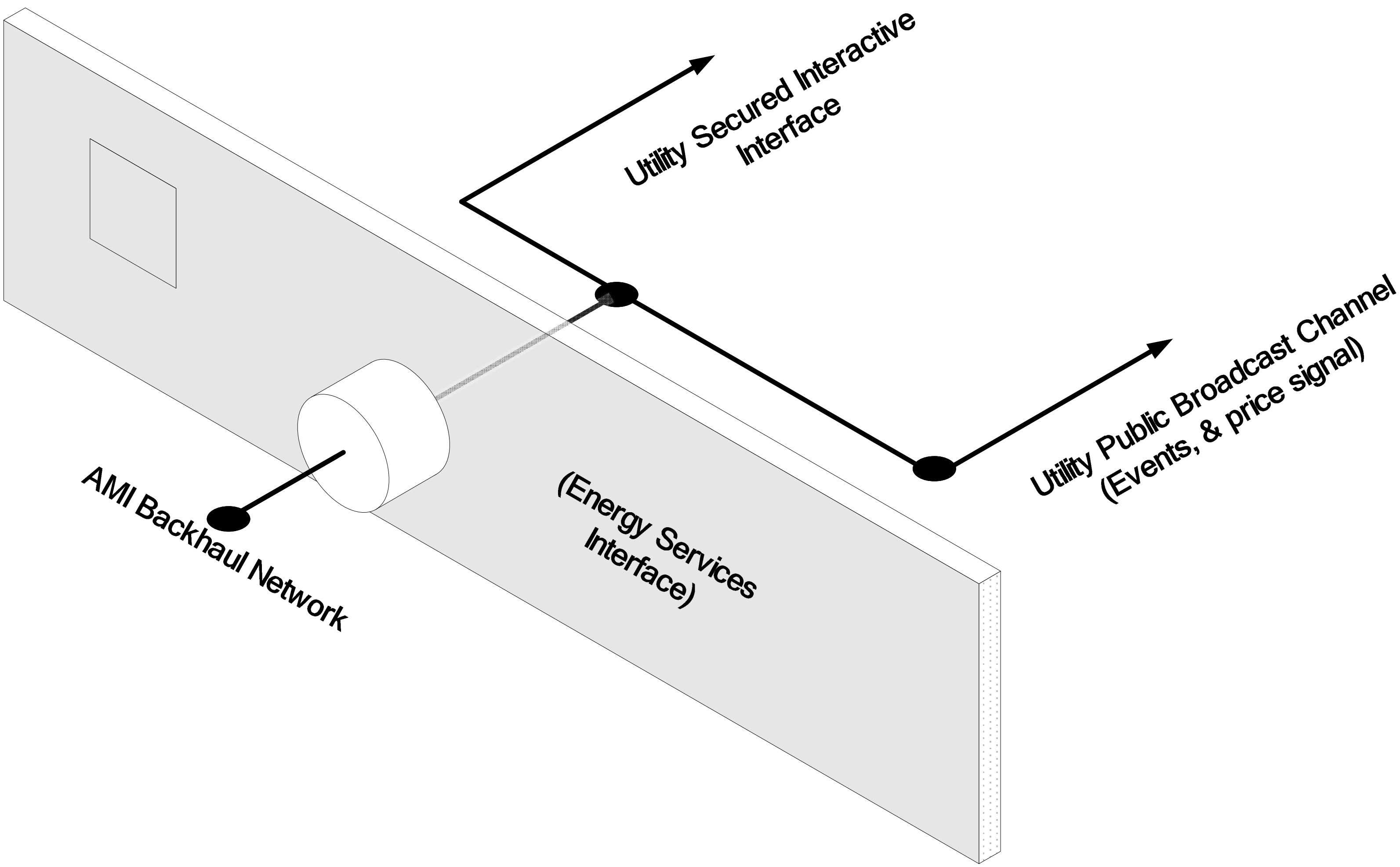
Device Mapping Example

Requ. ID	OpenHAN System Requirements	Energy Services Interface	PCT	Display	EMS	Load Control	HAN Electric Meter	HAN Meter (non-electric)	Smart Appliance
App.Control.1	HAN Device shall accept control signals from the Utility.	NA	B	B	B	B	B	B	B
App.Control.2	HAN Device shall respond to requests to cease operational state (e.g., open contact).	NA	B	NA	B	B	NA	NA	E
App.Control.3	HAN Device shall respond to requests to resume operational state (e.g., close contact).	NA	B	NA	B	B	NA	NA	E
App.Control.4	HAN Device shall acknowledge receipt of control signal.	NA	B	NA	B	B	NA	NA	E
App.Control.5	HAN Device shall acknowledge execution of control request.	NA	B	NA	B	E	NA	NA	O
App.Control.6	HAN Device shall acknowledge execution failure of request (i.e., exceptions).	NA	E	NA	E	E	NA	NA	O
App.Control.7	HAN Device shall signal any consumer-initiated overrides.	NA	B	NA	B	E	NA	NA	O
App.Control.8	HAN Device shall respond to request to cease operation state at a specific time.	NA	B	NA	B	E	NA	NA	O

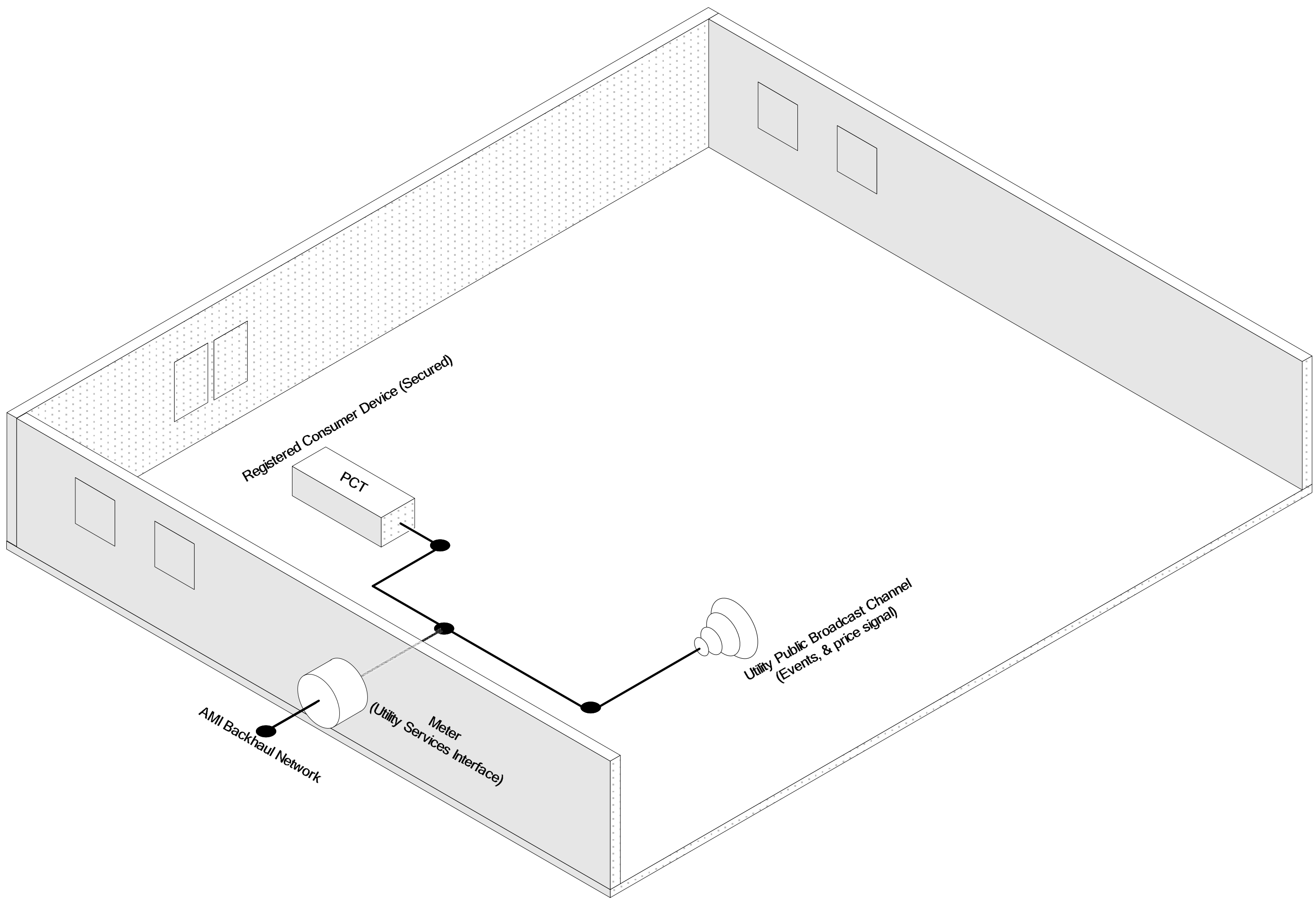
Architecture Considerations

- The architectural consideration section is not binding
- Provided for context
- Sections include:
  - *Utility Interface*
  - *Device Ownership*
  - *Public Broadcast Interface*
    - Broadcast ID (e.g., Utility ID, SSID)
    - Current Price (e.g., $0.XX/kWhr)
    - Relative Price (e.g., high, medium, low)
    - Message Expiration Time (e.g., 1 – 1440 minutes)
    - Rate Descriptor (e.g., residential, commercial, etc.)
    - Severity of Event Description (e.g., Stage 1, 2, 3)
    - Integrity check (e.g., CRC)
  - *Utility Secured Interface*
  - *Consumer Devices*
  - *Utility Devices*
  - *Cohabitation*
  - *Deregulated Utilities*
- Four Scenarios given as examples

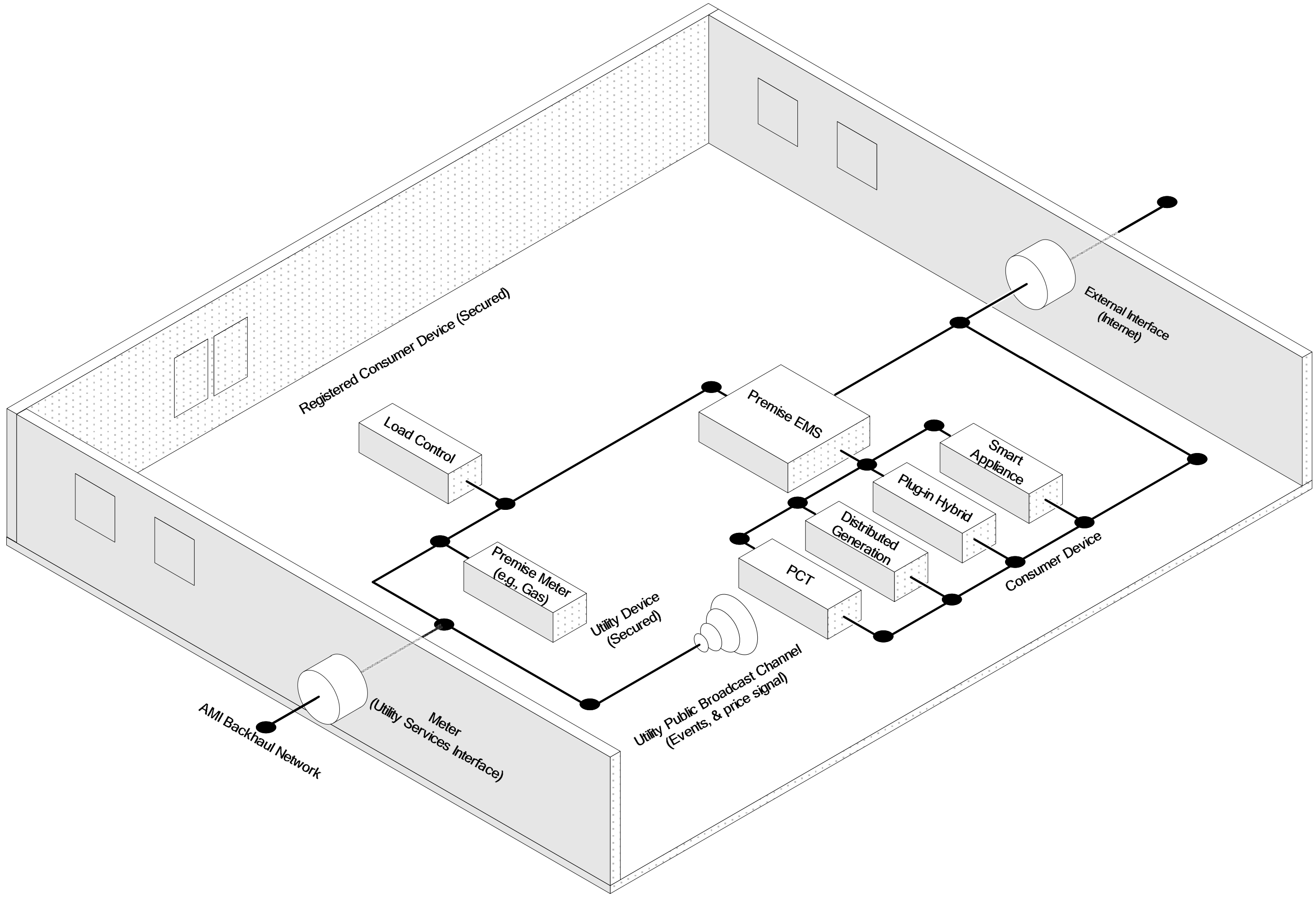
Interface


Utility Secured Interactive
Interface
Utility Public Broadcast Channel
(Events, & price signal)
AMI Backhaul Network
(Energy Services
Interface)

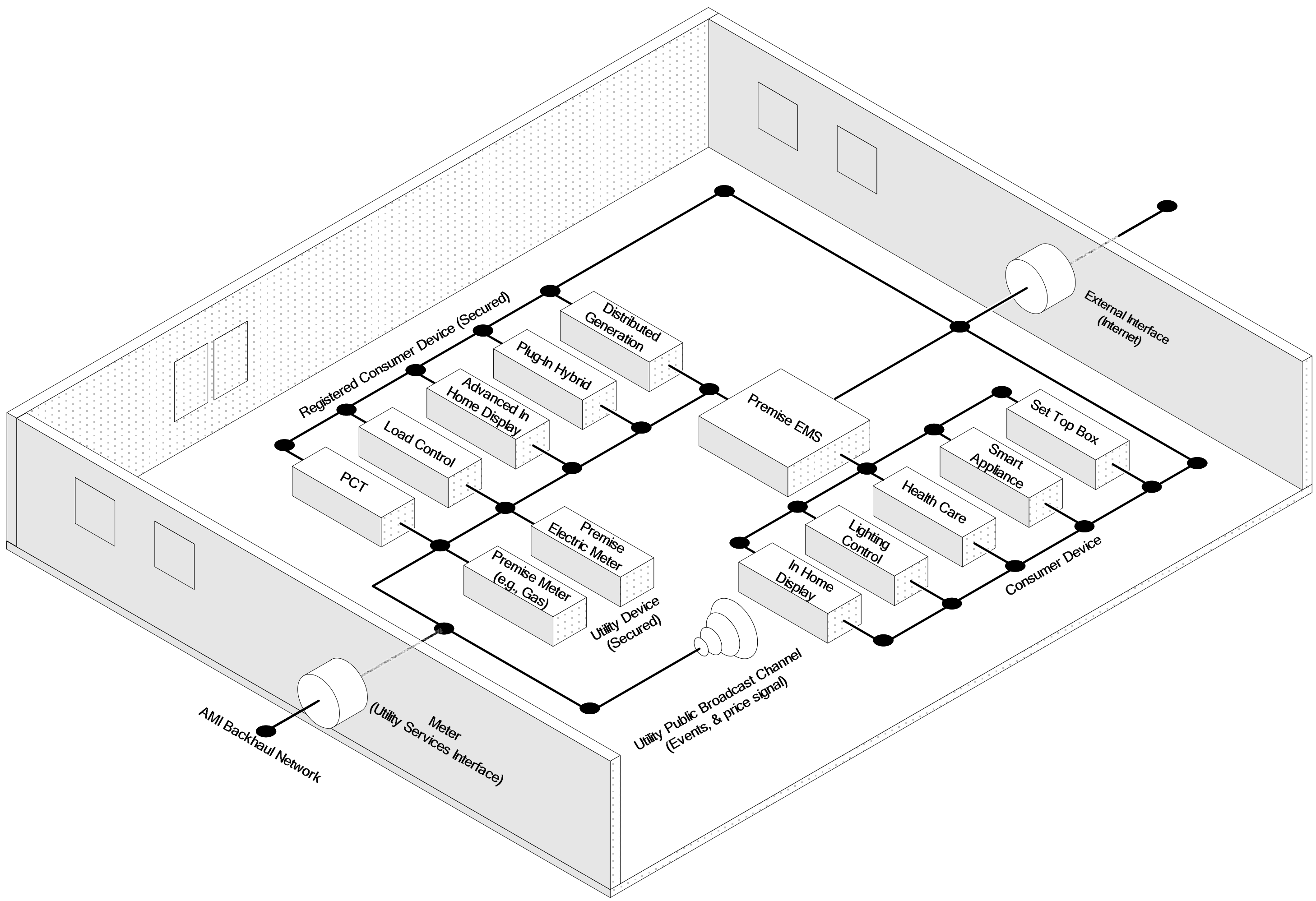
Scenario One (Inception)



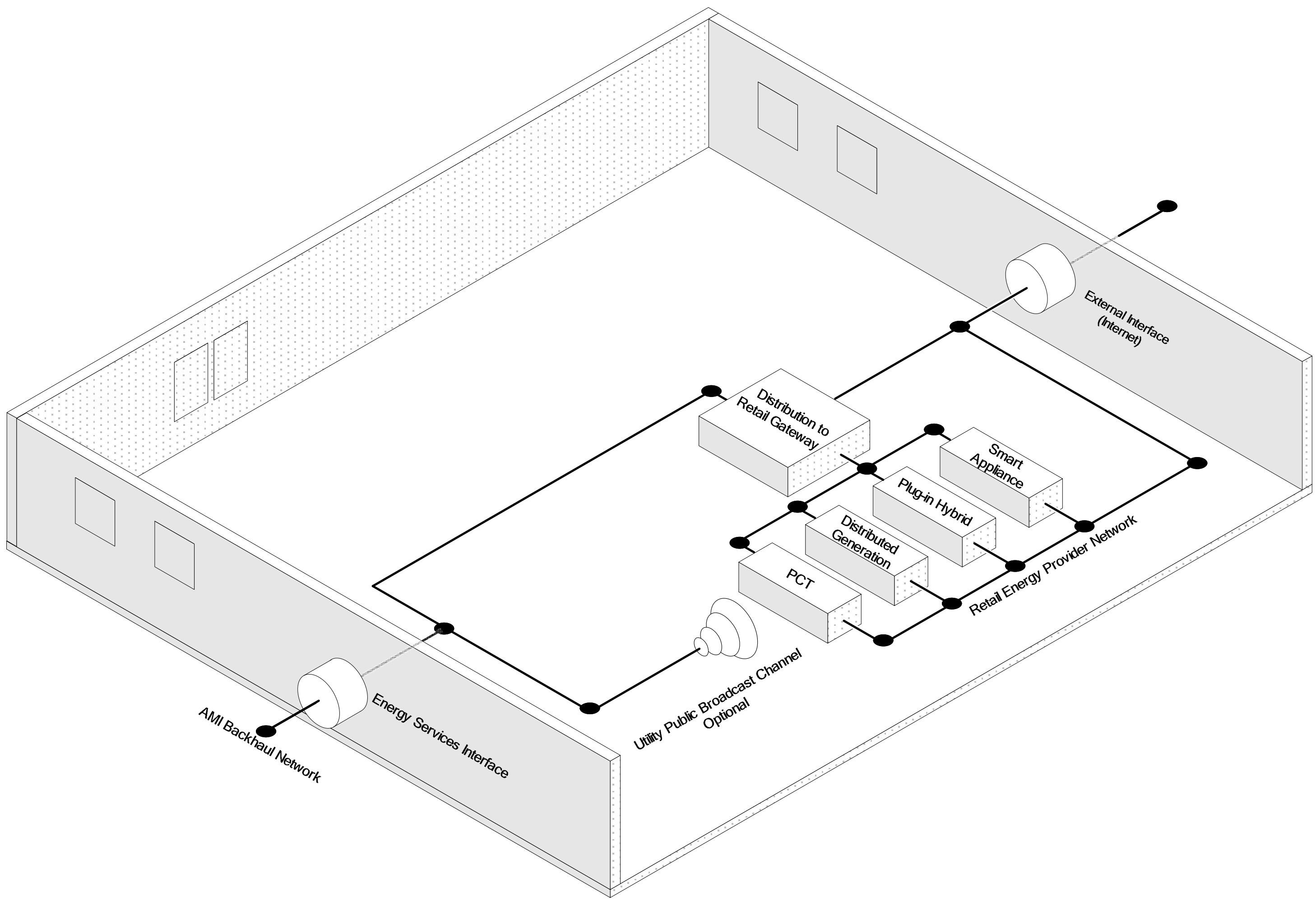
Scenario Two (Cohabitation)



Scenario Three (Mature)



Scenario Four (Deregulated)



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OpenHAN

- Questions before proceeding?

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Agenda

- Context Setting
  - EPRI Consumer Portal Project Overview
  - California Influence – AMI Reference Design
- Industry Response
  - OpenAMI Overview
  - UtilityAMI Overview
- OpenHAN
- **Security (AMI-SEC)**
- Questions and Discussion

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AMI Security Objectives

- *"AMI Security must facilitate the easy exchange of high resolution electric load and usage data between the customer and the utility while maintaining customer privacy and protecting critical infrastructure"*

Do the NERC CIPs Apply to AMI?

- The answer to this revolves around two key issues:
  - Definition of Critical Infrastructure
  - Placement of Electronic Security Perimeter

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Do the NERC CIPs Apply to AMI?

- CIP-002-1 Critical Cyber Asset Identification dictates that the utility will use a risk-based assessment to identify Critical Assets.

- The requirement relevant to AMI is the following item:
  - R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

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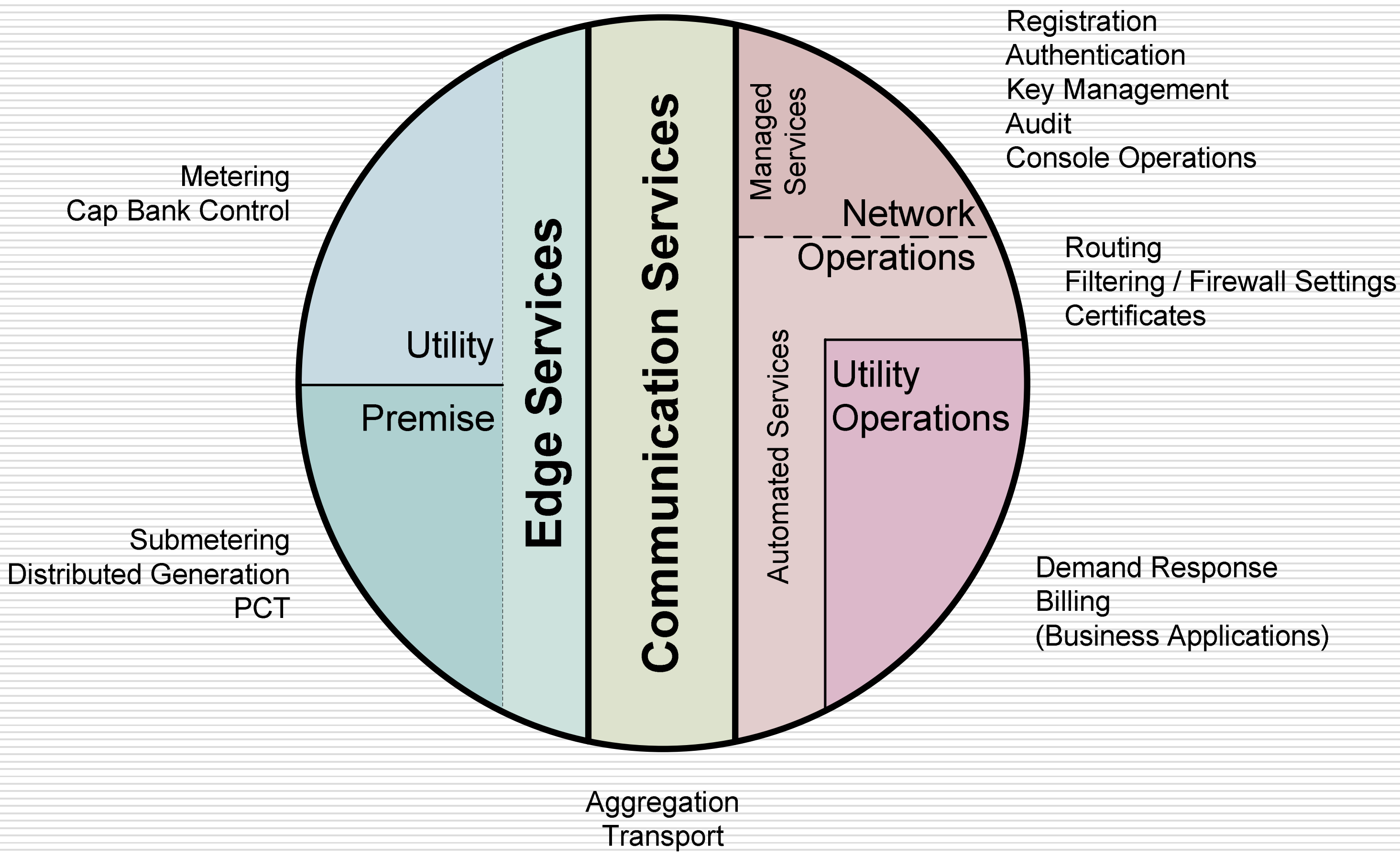
AMI-SEC Problem Space



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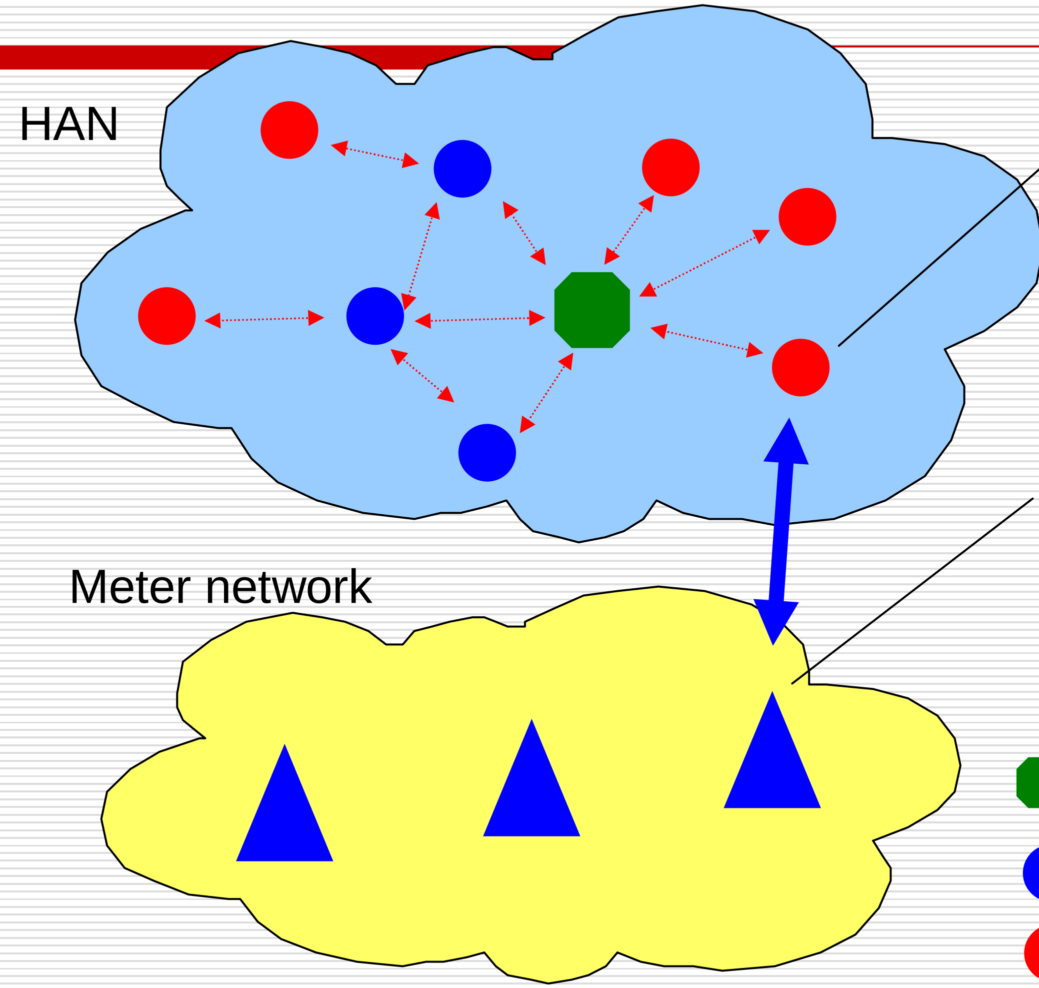
Example HAN Scenario



In-Home device communicates in HAN at network level

Meter wishes to communicate securely with device

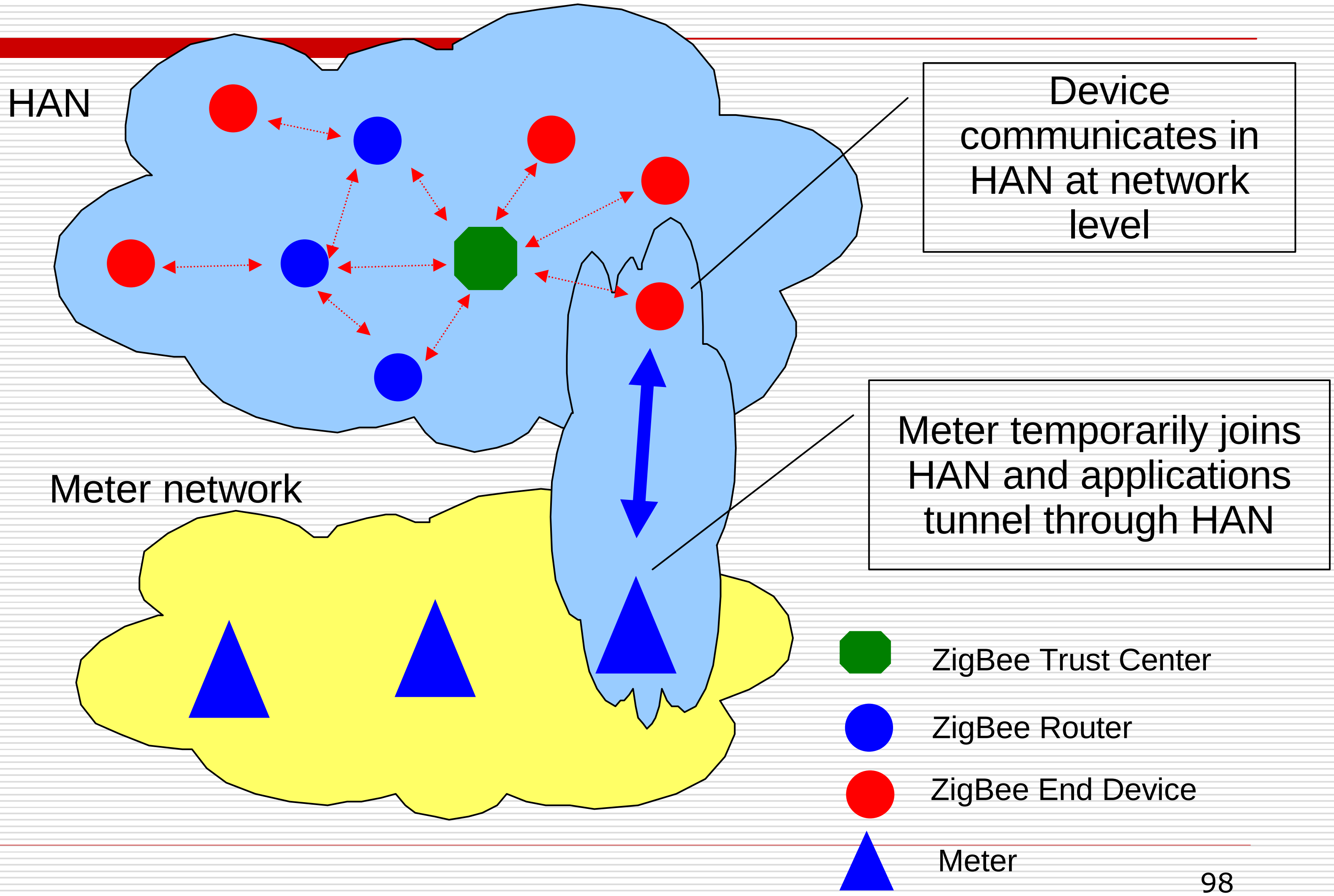
ZigBee Trust Center

ZigBee Router

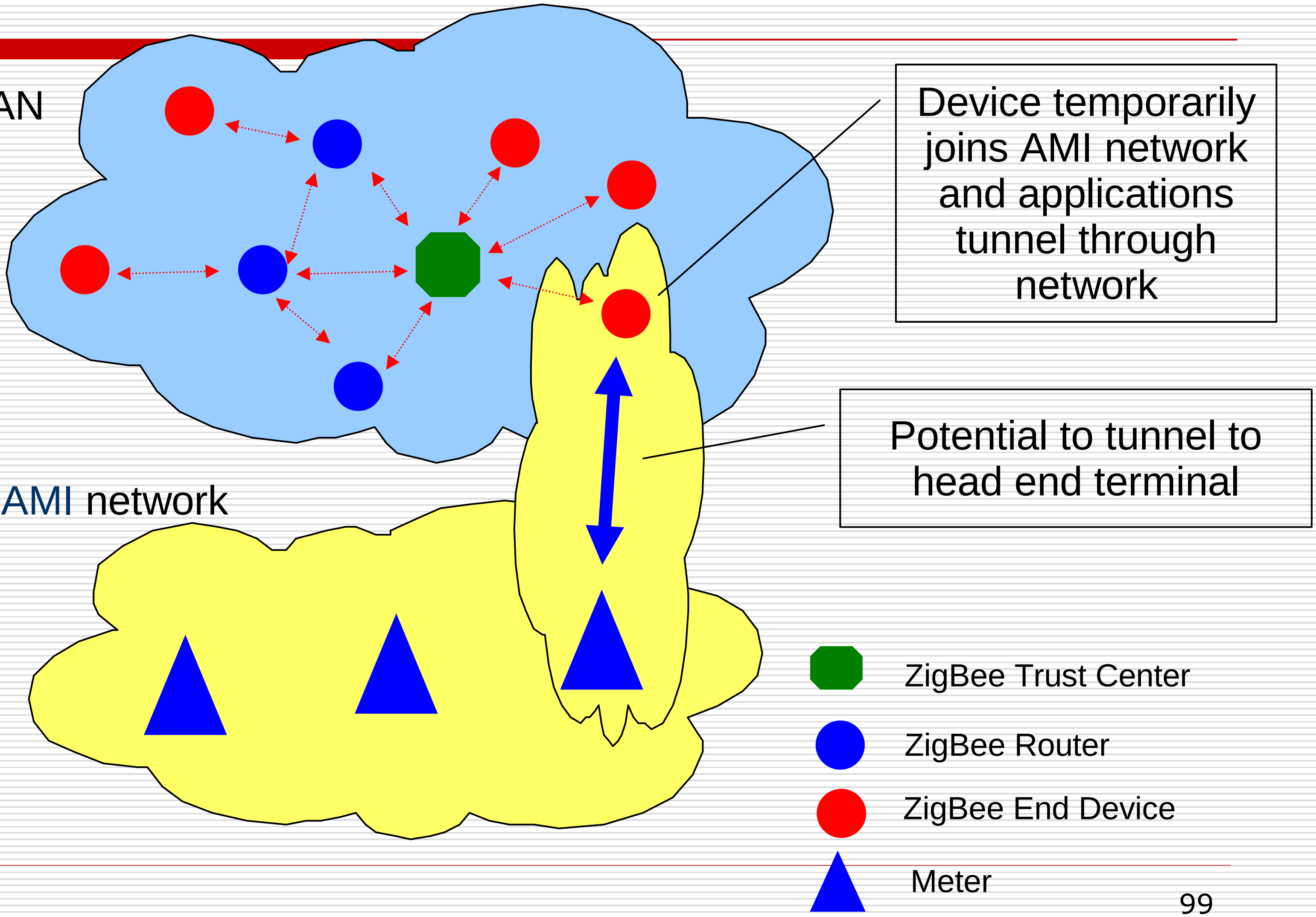
ZigBee End Device

Meter

1. Meter joins HAN



2. Utility device joins AMI network



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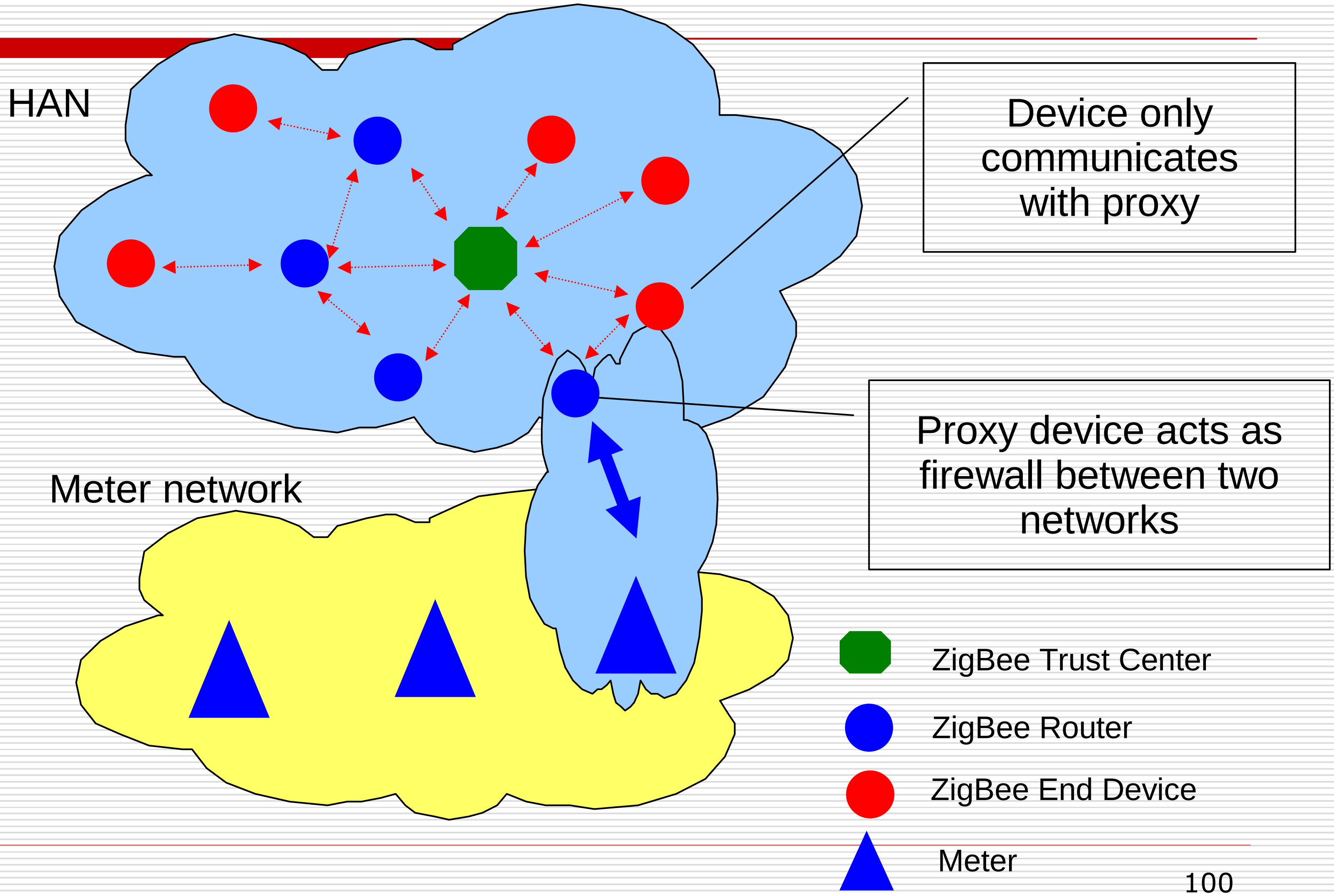
3. Proxy



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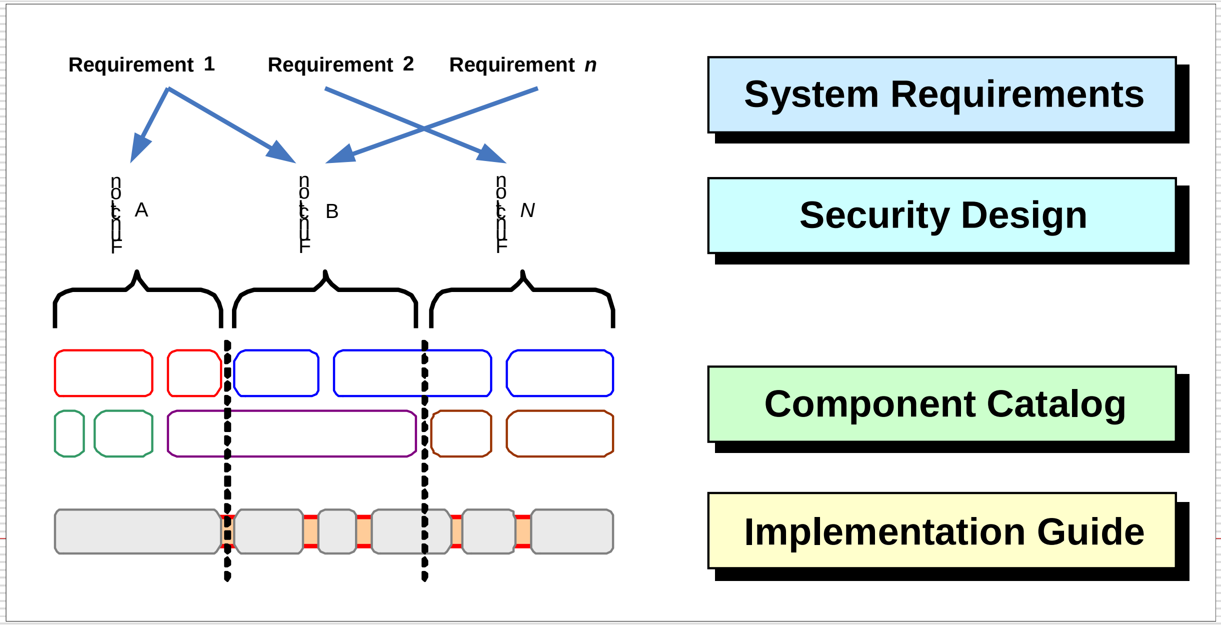
AMI-SEC Status

- Defined security domains
- Vetted OpenHAN Security requirements
- Acceleration program proposed
- Target June 2008



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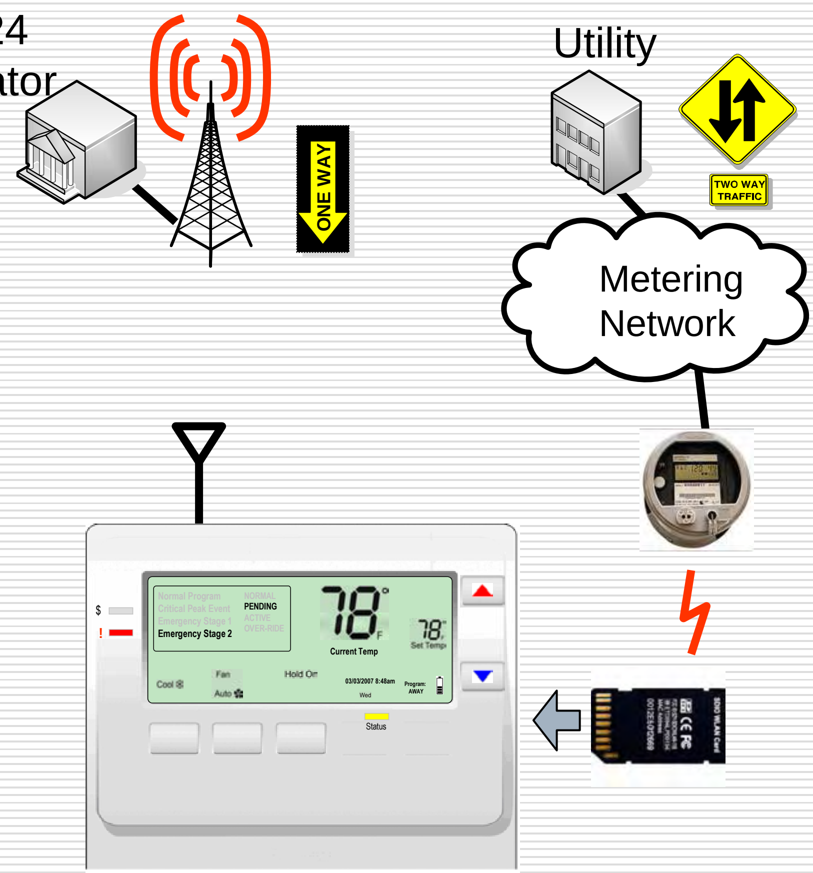
Programmable Communicating Thermostats

- Related to AMI Security
- Reduce load in emergency
- Broadcast sets back temp
- Prevent grid instability
- Two possible networks
- We're only addressing the broadcast network
- **WAS** to be required by law
- Builders install
- Two-way will override



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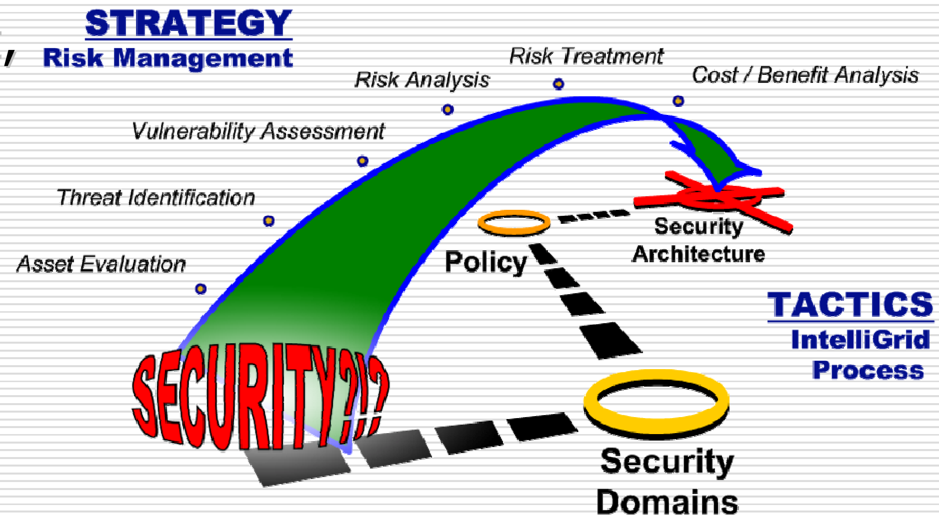
Risk Management Approach

- Assets
  - Value, Sensitivity Aspect (C-I-A)
- Threats
  - Possible Source, Intent, StrengthVulnerabilities
  - Frequency x Severity
- Mapping
  - Threats through Vulnerabilities to Assets
- Mitigation
  - Reduce, Transfer, Accept



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Some Possible Attacks

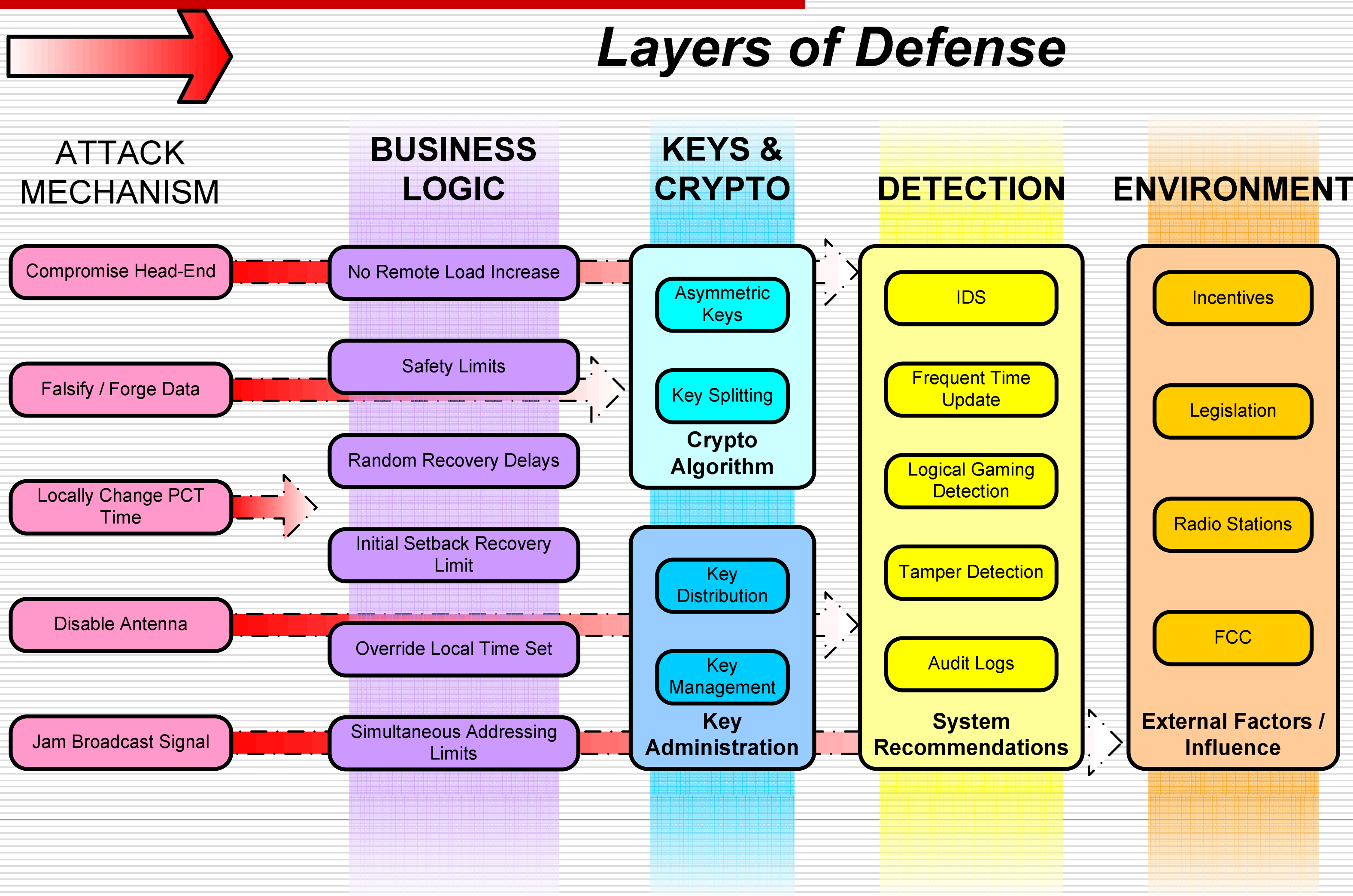
Mechanisms

- Compromise head-end
- Denial of service
- Jamming
- False packets
- Disconnect antenna

Effects

- Create sudden load
  - Cause grid instability
- Prevent load reduction
  - Force blackouts
  - Increase costs
- Shut down A/C for all
  - Discomfort
  - Annoyance
  - Affect health and safety
- Change time
  - Make system less effective
- "Game" the system
  - Avoid personal discomfort

Mitigation Methods



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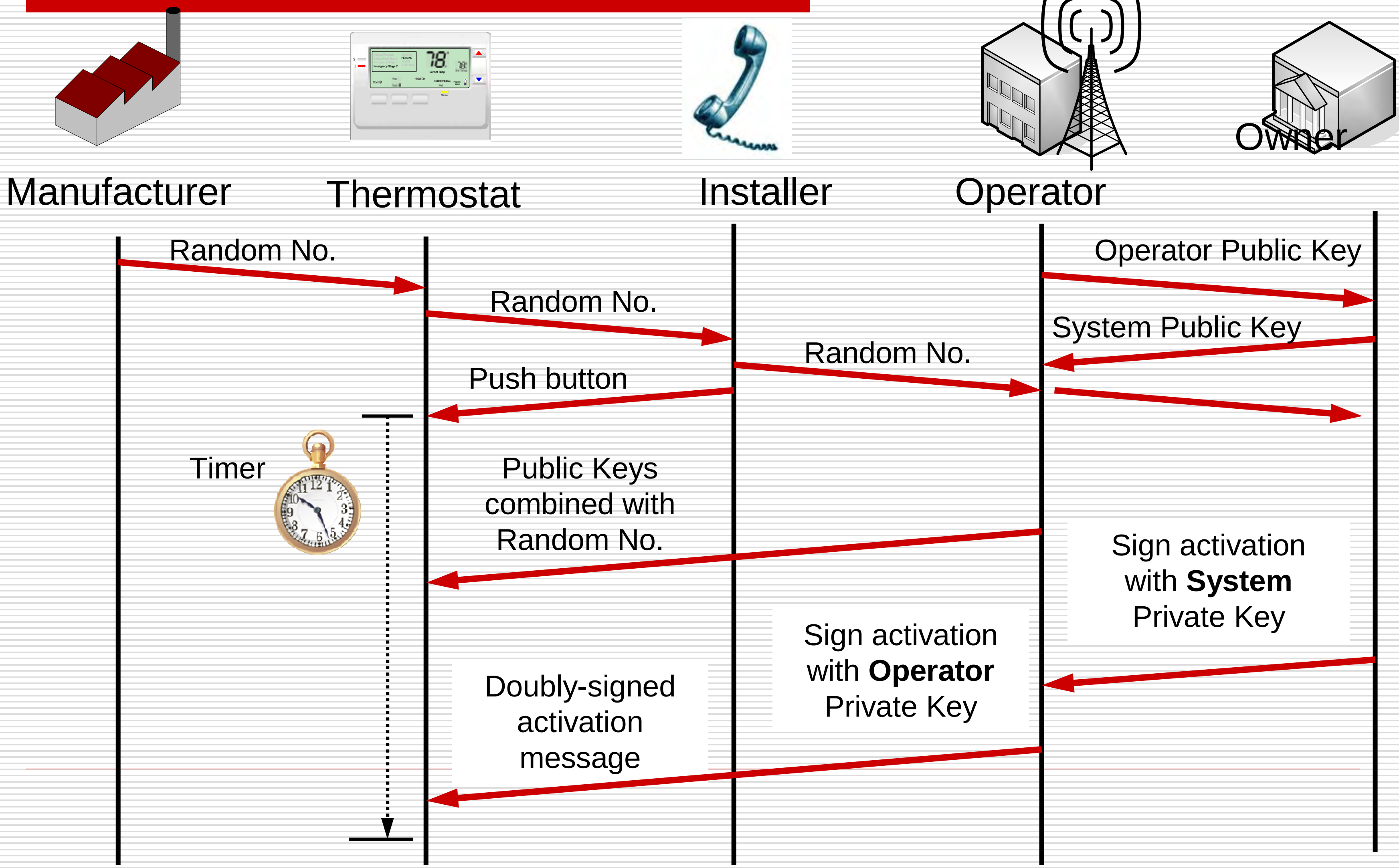
PCT Key Management



Discussion and Questions

- What are the challenges?
- What should be the approach?
- How does it affect your system?

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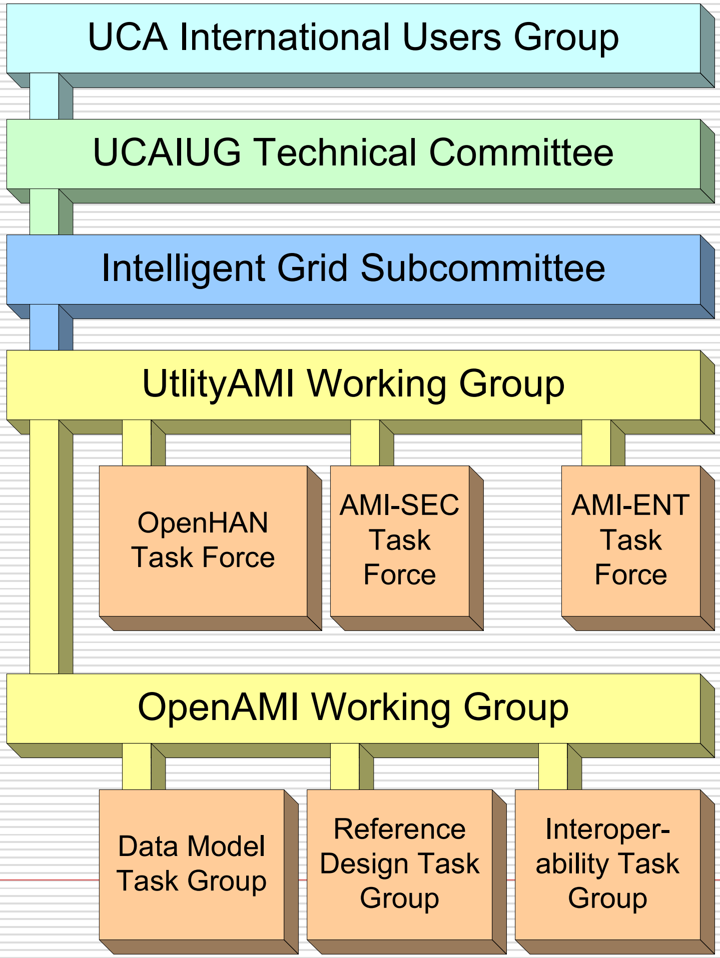
Come Participate!

- **UtilityAMI**
  General Requirements
- **OpenAMI**
  Vendors building stuff
- **OpenHAN**
  HAN Requirements
- **AMI-SEC**
  Security Geeks Only
- **OpenPCT**
  Status pending…
- **AMI-Enterprise**
  SOA for MDMS / CIS



Contact Us

For any additional information, please do not hesitate to contact us

EnerNex Corporation
Phone: 865-691-5540 ext. 114

grant@enernex.com
www.enernex.com

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http://sharepoint.ucausersgroup.org/
http://sharepoint.ucausersgroup.org/openami/
http://sharepoint.ucausersgroup.org/openhan/
http://sharepoint.ucausersgroup.org/utilityami/amisec/

22.0 Reference: Amended Application, page 5

Preamble: The first paragraph states that the HAN is defined as "the technology to communicate with in-home display devices but does not include the display devices themselves. …would display electrical consumption and pricing information in the customer's building". The last paragraph states that "this would enable FortisBC and its customers to control certain household appliances and subsequently reduce residential loads during critical peak periods".

Q22.1 Please clarify whether the HAN:

- **Simply allows (with the addition of in-home display devices) customers to understand their electricity usage in real time which could lead to them or FortisBC controlling their usage through other means and devices, or**
- **Allows (with the addition of further devices) customers/FortisBC to implement control technologies that were directly tied to the price and usage signal. (i.e., the HAN enables direct communication with control devices)**

A22.1 The HAN can communicate with both load control devices and in-home displays, and therefore either of the above scenarios would be possible in the future.

Q22.2 Under the revised AMI project, will customers be able to access information regarding their hourly usage through the web?

- **If so, how soon after a particular day/hour will the information be available?**
- **Are the costs of introducing this "web capability" included in the revised cost estimate?**
- **If not, what is the "cost" of providing this web capability and how would this change the Rate Impact Analysis (per page 14)?**

A22.2 Through web access, hourly usage data will be available within 24 hours of the time the power was consumed. The cost of this web capability is included in the original estimate. There are no incremental costs as a result of modifying the read requirements from daily readings to hourly readings.

Q22.3 Can any benefits be attributed to HAN (and the subsequent installation of in-home display devices) without the adoption of Time-of-Use or Critical Peak Pricing. If yes, please describe the benefits and the circumstances under which they would arise.

A22.3 There may be some conservation effects that could be achieved with an in-home display without implementing time-based rates, particularly if combined with a customer education program. The persistence and magnitude of any energy conservation achieved in this manner is not known to FortisBC.

Q22.4 Please describe precisely what changes in equipment specifications/capabilities have been included in the revised proposal as a result of the inclusion of HAN, in terms of:

- **The AMI-enabled meters,**
- **The Network Infrastructure to collect data from (and now send information to) each meter point and to communicate with FortisBC's information systems, and**
- **The central IT Infrastructure (including Billing Systems)**

A22.4 Changes to specifications/capabilities as a result of the inclusion of the HAN communications infrastructure are as follows:

- The AMI-enabled meters will now include a communications module that facilitates the future addition of HAN devices;
- There were no additions or changes to the network infrastructure as a result of the addition of the HAN communications module; and
- There were no additions or changes to the IT infrastructure as a result of the addition of the HAN communications module.

Q22.5 Apart from the costs associated with the purchase and connection of the in-house display devices, would there be any additional costs associated with introducing such display devices in the future (e.g., upgrades/improvements to the communication infrastructure and/or FortisBC's central IT systems)? If yes, please describe what these costs would be.

A22.5 It is not expected that there would be any additional costs as a result of improvements to the communications infrastructure as a result of implementing in-home display devices. IT systems may require modifications in order to transmit required information to the in-home displays and to ensure the security of data retained by in-home displays when they are moved to a new location or when new the device is transferred to a new customer.

Q22.6 What are the costs associated with the purchase and connection of the various types of in-home display devices mentioned in the Amended Application? Will costs of these devices be borne by individual ratepayers or by FortisBC? Are any of these costs included in the Amended Application?

A22.6 Please refer to the response to BCUC IR No. 3 Q42.1.

Q22.7 What are the costs associated with the purchase and connection of home appliance load controlling devices? Will costs of these devices be borne by individual ratepayers or by FortisBC? Are any of these costs included in the Amended Application?

A22.7 The cost of a load control device is approximately $75 per appliance. At this point, it has not been determined whether the devices would be provided by the utility or would be the responsibility of the ratepayers. As with the in-home display units, this decision is primarily linked to the design of any time based rates, and cost-related issues will form part of the rate design process. For this reason, the costs of load control devices and in-home displays are not included within the AMI project costs in the Amended Application. Please also refer to the response to BCUC IR No. 3 Q42.1.

Q22.8 Which North American jurisdictions have implemented the AMI technology proposed in FortisBC's Amended Application?

A22.8 The largest Canadian implementation of hourly readings and a VEE equipped MDMR is Ontario. Several jurisdictions in the United States are also considering or have implemented similar technologies including California, Oregon and NY State. It is the understanding of FortisBC that BC Hydro intends to implement the functionality described in the FortisBC AMI Amended Application. Please also see the response to BCUC IR No. 3 Q50.1.2.

23.0 Reference: Amended Application, page 6

Q23.1 Can any benefits be attributed to Hourly Reading without the adoption of Time-of-Use or Critical Peak Pricing? If yes, please describe the benefits and the circumstances under which they would arise.

A23.1 The benefits of hourly readings come from the higher granularity of data provided by the AMI system. This data can be used to better understand consumption patterns for load forecasting, capital planning, resource acquisition and revenue protection. In addition, it can also be used to complete more accurate feeder-to-meter reconciliations to identify system losses. The primary benefit to customers is the ability to see hour-by-hour electrical consumption at their premise. If the customer is experiencing a high bill, the customer and the contact center will be better able to pinpoint the exact hours that the consumption occurred thereby providing better service to customers.

Q23.2 Please describe precisely what changes in the equipment specifications/capabilities have been included in the revised proposal as a result of the inclusion of Hourly Reading requirements, in terms of:

- **The AMI-enabled meters,**
- **The Network Infrastructure to collect data from (and now send information to) each meter point and to communicate with FortisBC's information systems, and**
- **The central IT Infrastructure (including Billing Systems)**

A23.2 There are no changes required to the AMI-enabled meters to accommodate hourly readings. The network infrastructure will be required to have sufficient bandwidth to accommodate the increased level of reading activities.

The central IT infrastructure will be upgraded to include a VEE equipped MDMR which is a more complex MDMR system than was contemplated in the Original Application. Because FortisBC's current rates only require one reading every billing period (monthly or bi-monthly) to be transferred from the MDMR to the billing system, the interface to the CIS Billing System is not expected to be impacted.

Q23.3 One of the goals of the AMI Amended Application appears to be to identify opportunities to use rates as a mechanism to motivate customers to either use less electricity or to use less electricity as specific times. Has FortisBC considered implementing smart meter pilot projects targeting residential customers with higher than average electricity use in order to measure the potential for demand reduction? If not, why not?

A23.3 FortisBC will consider implementing rate design pilot projects targeting high-use residential customers, although it is likely that the response of these customers can be modeled with a pilot for all types of customers within the residential class. One benefit to implementing hourly readings through AMI is that hourly profile data will be available for all customers. This data will allow FortisBC to better understand consumption patterns of individual customer classes and to use this data to model the effect certain time-based rates would have on these customers. Once AMI is implemented, FortisBC intends to utilize the AMI system to test a variety of DR and DSM tools, including time-based rates, automated load control and in-home display of energy use data. Judging from the experience of other jurisdictions, it is likely that a combination of the above tools will result in the most effective DR and DSM response from FortisBC customers.

The functionality provided by the AMI system described in the Amended Application, which includes support for in-home displays, verified hourly readings and load control will make these studies more effective and less costly than they would be otherwise with the existing metering and communications infrastructure.

24.0 Reference: Amended Application, page 12

Q24.1 Please describe how FortisBC established the value of the additional software maintenance costs associated with the more complex MDMR (including VEE capability)?

A24.1 The increased software maintenance costs associated with the VEE equipped MDMR was based on FortisBC's previous experience with software maintenance agreements.

Q24.2 If information on the potential costs was obtained from more than one source, please indicate the range of cost estimates obtained – relative to the $203,000 quoted in the Application.

A24.2 Please see the response to BCOAPO IR No. 3 Q24.1.

25.0 Reference: Amended Application, page 13

Q25.1 Please describe how FortisBC established the value for the additional costs associated with lines (i) through (iii) in Amended Table 6.3.

A25.1 The additional costs in lines (i) Meters and Modules, and (ii) Network Infrastructure reflect a narrowing of the potential vendors capable of supplying the additional functionality which FortisBC believes may increase the AMI infrastructure costs.

The additional costs in line (iii) IT Infrastructure and Upgrades are driven primarily by the added VEE functionality as described in the Amended Application. These costs were estimated by FortisBC based on experience and knowledge of the industry.

Q25.2 If information on the potential costs was obtained from more than one source, please indicate the range of cost estimates obtained for each of the three items.

A25.2 Additional costs were estimated by FortisBC based on its knowledge of the industry.

As described in the response to BCOAPO IR No. 3 Q25.1, FortisBC applied an increment to lines (i) Meters and Modules, and (ii) Network Infrastructure based on an expectation that vendor restriction will increase the cost of the AMI system, however, this cannot be confirmed until an RFP has been completed.

As described in response to BCOAPO IR No. 3 Q25.1, the cost estimate for line (iii) IT Infrastructure costs is comparable to costs incurred by other utilities of similar sizes implementing similar software.

Q25.3 Given the added complexity of the project, why are the project management costs unchanged?

A25.3 Please refer to the response to BCUC IR No. 3 Q62.1

Q25.4 Please provide an updated version of Table 6.3.2 from the Original Application.

A25.4 An updated version of Table 6.3.2 has been included below.

Table 6.3.2: Amended Summary of IT Infrastructure Costs

	Estimated Costs ($000s)
Software and Reporting Tools	3,842
Interfaces to Existing Systems	279
Billing System Enhancements	530
Work Order Management Interface	235
Hardware Requirements	128
Total IT Infrastructure Costs	**5,014**

Q25.5 Please provide a discussion (similar to that on pages 31-32 of the Original Application) that outlines the "new" requirements in each of the 5 areas identified.

A25.5 Of the five areas listed on pages 31-32 of the Original Application (Exhibit B-1), the only area that contains "new" features or requirements with the Amended Application is the one titled "Software and Reporting Tools" (primarily VEE).

In this section, an additional bullet under the listed functionality should read:

- Provide estimates for any gaps in hourly readings using Validation, Estimation and Editing (VEE) capability.

The final line on page 31, line 21 should read as follows:

The cost of the AMI software solution (including the original estimate plus the increase from the Amendment) is expected to be $3,842,000.

Q25.6 Given that there are additional Meters and Modules costs associated with the Amended Application, why are the "Incremental Meter Costs" reported in Amended Table 6.3 also not higher?

A25.6 The incremental meter costs reflect only the increased cost of the metering endpoint rather than the entire category of "meters and modules". Therefore, not all additional costs for the Amended Application should be added to the incremental meter costs. However, approximately $3 per meter in cost additions for the Amended Application should have been added to the incremental meter cost category to reflect the addition of the HAN communications module. This would increase the incremental meter expenses from $1,336,000 to $1,444,000. An amended Table 6.3 is shown in Errata No. 2.

26.0 Reference: Amended Application, pages 13-14

Q26.1 What would be the cost (in 2008$) of implementing the HAN and Hourly Reading Capabilities at a future point in time (assuming AMI was implemented as per the original Application?

A26.1 If HAN and hourly reading capabilities are not included in the initial implementation of AMI, it may not be possible to upgrade the system at a future point to accommodate these functions. In most cases, the meters and network infrastructure would need to be removed and replaced to accommodate these new features.

Because this would render a significant component of the project redundant, the cost (in 2008 dollars) to add these features later would likely be in the range of $25 million to $35 million in addition to the costs presented in the Original Application.

Q26.2 Please re-do the Rate Impact Analysis (page 14) assuming:

- **The Original Application is approved an implemented as submitted**
- **The HAN and Hourly Reading options are introduced in 2011**

A26.2 Please refer to the response to BCOAPO IR No. 3 Q26.1. As this scenario would essentially double the cost of the project and the associated timelines, this scenario was not provided. FortisBC believes that it would not be prudent to implement an AMI system only to fully replace it the year after implementation.

27.0 Reference: Amended Application, page 16

Q27.1 With respect to lines 9-10, please confirm that without additional spending on in-house display devices, the HAN and Hourly Reading capabilities cannot provide customers with real-time information on their hourly usage.

A27.1 Without additional spending on in-home display devices, hourly consumption information would not be available in real-time, but will be available to customers within 24 hours via a secure internet logon.

Q27.2 With respect to lines 12-14, assuming HAN and Hourly Reading were not implemented at this time, how much time would be required to implement these two options at a later date?

A27.2 Please see the response to BCUC IR No. 3 Q26.1. It is expected that such a future implementation would require 2 - 3 years to complete.

Q27.3 With respect to lines 7-8, please outline the benefits that will be derived from FortisBC having more detailed information (e.g., hourly usage data) about consumption patterns.

A27.3 Please refer to the response to BCOAPO IR No. 3 Q23.1.

28.0 Reference: Amended BCUC 1.2

Q28.1 Please clarify what is meant by "near real-time display". How much of a "lag" would there be?

A28.1 Near real-time in this context means less than one minute.

Q28.2 Would the display be capable of showing hourly use? If not, what level of granularity is possible?

A28.2 FortisBC is not aware of any in-home displays that do not support the display of hourly usage data. In-home displays usually offer various display options including:

- Colored lights indicating present TOU period (on or off peak);
- Current power consumption levels (kW and kWh);
- Graphical displays showing historical daily (usually 30 days) or hourly usage (usually 24 hours);
- Graphical displays showing historical daily (usually 30 days) or hourly cost information (usually 24 hours); and

Some displays can be configured remotely while others offer options to the customer to set their preferred display summaries.

29.0 Reference: Amended BCUC 12.0 (pages 35-36)

Q29.1 With respect to the C1 results presented on page 36, please explain why the NPV for the Status Quo changes, depending on the Deferral Period, whereas in the original response the value was constant. In particular, why isn't the Status Quo value constant?

A29.1 Please refer to the response to BCUC IR No. 3 Q52.1.

Q29.2 Please confirm that of the AMI scenarios set out in the response, Defer Three Years has the lowest cost. Please explain, at in general terms, why this is the case.

A29.2 The Defer Three Years scenario appears to have the lowest cost only because of the various assumptions included in the model. As can be seen in Table A29.2 below, all three scenarios result in essentially the same NPV. As the project is deferred the NPV of the capital cost decreases due to the discounting and the assumption that capital costs would remain essentially the same in nominal dollars. However, deferring the project increases the ongoing operating costs and it was assumed that they would escalate at a higher rate than general inflation.

Table A29.2 – Defer Three Years Scenario

	Deferral Term		
NPV	One Year	Three Years	Five Years
Capital Costs	29,201	24,993	21,474
Operating Costs	18,761	22,486	26,474
	47,962	47,479	47,948

30.0 Reference: Amended BCOAPO #7.2

Q30.1 Given the increased up-front capital costs, why haven't the expected replacement costs also increased from $48.000 in the Amended Application?

A30.1 As the $48,000 for equipment replacements was determined using a 5 percent annual failure rate on the cost of the communications hardware, that figure in the Amended Application should have should have been increased to $55,680. The correct figure is shown in Errata No. 2, BCOAPO IR No. 1 Amended A7.2.

Q30.2 If these costs need to be revised, please redo the Rate Impact Analysis with the updated values.

A30.2 The Rate Impact Analysis below now reflects the additional costs described in the responses to BCOAPO IR No. 3 Q25.6 and Q30.1.

Project No. 3698493: Advanced Metering Infrastructure (AMI) Project
Requestor Name: BCOAPO et al.
Information Request No: 3
To: FortisBC Inc.
Request Date: May 8, 2008
Response Date: May 22, 2008

Rate Impact
Option "AMI"

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
	Summary												
	Revenue Requirements												
1	Operating Expense (Incremental)	**(24,407)**	0	0	(518)	(2,381)	(2,502)	(2,629)	(2,752)	(2,890)	(3,032)	(3,181)	(3,334)
2	Depreciation Expense	**12,737**	0	0	761	1,662	1,666	1,669	1,661	1,664	1,667	1,670	1,673
3	Carrying Costs	**15,512**	0	641	2,014	2,686	2,567	2,438	2,310	2,191	2,071	1,951	1,822
4	Income Tax	**(583)**	0	(490)	(1,071)	(896)	(542)	(296)	(99)	61	191	296	387
5	Total Revenue Requirement for Project	**3,258**	0	151	1,185	1,071	1,189	1,182	1,120	1,026	896	737	548
	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
7	Rate Impact		0.00%	0.06%	0.46%	0.39%	0.41%	0.40%	0.37%	0.34%	0.29%	0.23%	0.17%
8	**NPV of Project / Total Revenue Requirements**		**0.11%**										
	Regulatory Assumptions												
9	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
10	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
11	Equity Return		9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
12	Debt Return		6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
13	AFUDC		6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%
	Capital Cost												
14	Capital Investment		551	15,992	19,627								
15	Incremental meter costs		0	118	105	85	66	67	67	66	65	63	61
16	Avoided Itron Purchase (2013 & 2018)		0					(250)					(250)
16	AFUDC		17	500	613								
17	Total Construction Cost in Year		568	16,610	20,345	85	66	(183)	67	66	65	63	(189)
18	Cumulative Construction Cost		568	17,179	37,524	37,609	37,675	37,492	37,559	37,626	37,690	37,753	37,565
19	Land												
20	Net Cost of Removal												
21	Total Capital Cost in Year		568	16,610	20,345	85	66	(183)	67	66	65	63	(189)
22	Cumulative Capital Cost		568	17,179	37,524	37,609	37,675	37,492	37,559	37,626	37,690	37,753	37,565
23	Additions to Plant in Service		0	17,179	20,345	85	66	(183)	67	66	65	63	(189)
24	Cummulative Additions to Plant		0	17,179	37,524	37,609	37,675	37,492	37,559	37,626	37,690	37,753	37,565
25	CWIP		568	0	0	0	0	0	0	0	0	0	0

	Annual Operating Costs / (Savings)											
	Savings											
26	Annual Meter Reading Savings	-	-	(592)	(2,491)	(2,611)	(2,736)	(2,856)	(2,992)	(3,133)	(3,280)	(3,431)
27	Annual Customer Service Savings	-	-	(74)	(307)	(316)	(324)	(333)	(343)	(352)	(362)	(371)
29	Annual Operations Savings	-	-	-	(318)	(329)	(340)	(351)	(363)	(375)	(387)	(399)
	Costs											
32	Incremental Labour		-	148	296	304	314	323	333	343	353	364
33	Software Service Agreement		-	-	242	246	251	256	262	267	272	278
34	Communications		-	-	142	145	148	151	154	157	160	163
35	Equipment Replacements		-	-	56	57	58	59	60	61	63	64
					0	0	0	0	0	0	0	0
36	Total Incremental Operating Costs (Savings)	0	0	(518)	(2,381)	(2,502)	(2,629)	(2,752)	(2,890)	(3,032)	(3,181)	(3,334)
					735							
	Depreciation Expense											
37	Opening Cash Outlay	0	0	17,179	37,524	37,609	37,675	37,492	37,559	37,626	37,690	37,753
38	Additions in Year	0	17,179	20,345	85	66	(183)	67	66	65	63	(189)
39	Cumulative Total	0	17,179	37,524	37,609	37,675	37,492	37,559	37,626	37,690	37,753	37,565
40	Depreciation Rate - composite average	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%
41	Depreciation Expense	0	0	761	1,662	1,666	1,669	1,661	1,664	1,667	1,670	1,673
	Net Book Value											
42	Gross Property	0	17,179	37,524	37,609	37,675	37,492	37,559	37,626	37,690	37,753	37,565
43	Accumulated Depreciation	0	0	(761)	(2,423)	(4,090)	(5,759)	(7,420)	(9,084)	(10,750)	(12,420)	(14,093)
44	Net Book Value	0	17,179	36,763	35,186	33,586	31,734	30,140	28,542	26,940	25,333	23,472
	Carrying Costs on Average NBV											
45	Return on Equity	0	310	973	1,298	1,241	1,178	1,116	1,059	1,001	943	880
46	Interest Expense	0	331	1,041	1,388	1,327	1,260	1,194	1,132	1,070	1,008	941
47	AFUDC	0	0	0	0	0	0	0	0	0	0	0
48	**Total Carrying Costs**	0	641	2,014	2,686	2,567	2,438	2,310	2,191	2,071	1,951	1,822
	Income Tax Expense											
49	Combined Income Tax Rate	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return											
50	Return on Equity	0	310	973	1,298	1,241	1,178	1,116	1,059	1,001	943	880
51	Gross up for revenue (Return / (1- tax rate)	0	449	1,390	1,815	1,700	1,614	1,529	1,450	1,371	1,292	1,206
52	Income tax on Equity Return	0	139	417	517	459	436	413	392	370	349	326

	Income Tax on Timing Differences											
53	Depreciation Expense	0	0	761	1,662	1,666	1,669	1,661	1,664	1,667	1,670	1,673
54	Less: Capital Cost Allowance	0	1,401	4,233	5,209	4,372	3,649	3,044	2,559	2,152	1,811	1,506
55	Total Timing Differences	0	(1,401)	(3,472)	(3,547)	(2,705)	(1,980)	(1,383)	(895)	(485)	(141)	167
56	Gross up for tax (Total Timing Differences/(1-tax rate))	0	(2,031)	(4,960)	(4,960)	(3,706)	(2,712)	(1,895)	(1,225)	(664)	(194)	229
57	Income tax on Timing Differences	0	(630)	(1,488)	(1,414)	(1,001)	(732)	(512)	(331)	(179)	(52)	62
60	**Total Income Tax**	0	(490)	(1,071)	(896)	(542)	(296)	(99)	61	191	296	387
	Capital Cost Allowance											
61	Opening Balance - UCC	0	0	15,778	31,890	26,766	22,460	18,629	15,651	13,159	11,072	9,324
62	Additions	0	17,179	20,345	85	66	(183)	67	66	65	63	(189)
63	Subtotal UCC	0	17,179	36,123	31,975	26,832	22,278	18,695	15,717	13,223	11,135	9,135
64	Capital Cost Allowance Rate	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%
65	CCA on Opening Balance	0	0	2,574	5,202	4,366	3,664	3,039	2,553	2,147	1,806	1,521
66	CCA on Capital Expenditures (1/2 yr rule)	0	1,401	1,659	7	5	(15)	5	5	5	5	(15)
67	Total CCA	0	1,401	4,233	5,209	4,372	3,649	3,044	2,559	2,152	1,811	1,506
68	Ending Balance UCC	0	15,778	31,890	26,766	22,460	18,629	15,651	13,159	11,072	9,324	7,629

31.0 Reference: Amended BCOAPO #16.2

Q31.1 Will requiring the capability to store thirty days of "hourly" readings (as opposed to daily readings) increase the cost of the meters?

A31.1 No. Costs related to providing hourly readings, including the additional memory required for thirty days of storage, are included in the stated cost.

Q31.2 If not, why not? If yes, is this incremental cost included in the revised project cost estimate?

A31.2 The cost is included.

32.0 Reference: Amended BCOAPO #21.5

Q32.1 Please confirm that the $8.8 M value quoted in the response is "equivalent" to the $3.164 M value quoted on page 14 of the amended Application – based on the revised assumptions in the question. If not, please provide the "equivalent" value.

A32.1 Confirmed.

Q32.2 The original question requested using a 15-year amortization period that was meant to reflect a change in assumption regarding the service life of the "smart meter". Please re-do the Rate Impact Analysis, assuming that the meter's service life is only 15 years and must be replaced at that point in time.

A32.2 Please see the Rate Impact Analysis below. Please also refer to the responses to BCUC IR No. 3 Q55.1.

Revenue Requirements Option "AMI" Amended Application

BCOAPO IR3 32.2

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
	Summary											
	Revenue Requirements											
1	Operating Expense (Incremental)	**(24,605)**	0	0	(516)	(2,377)	(2,497)	(2,624)	(2,746)	(2,883)	(3,026)	(3,174)
2	Depreciation Expense	**24,395**	0	0	3,106	5,435	5,441	4,082	3,088	2,056	2,060	2,064
3	Carrying Costs	**14,132**	0	742	2,225	2,767	2,366	2,015	1,752	1,564	1,415	1,266
4	Income Tax	**3,698**	0	(468)	(22)	624	820	521	331	95	221	321
5	Total Revenue Requirement for Project	**17,620**	0	273	4,794	6,450	6,129	3,994	2,424	832	670	477
6												
7												
8	**Rate Impact**											
9	Forecast Revenue Requirements	**3,042,076**	219,817	240,023	255,139	272,208	287,690	293,400	299,300	305,300	311,400	317,600
10	Rate Impact		0.00%	0.11%	1.88%	2.37%	2.13%	1.36%	0.81%	0.27%	0.22%	0.15%
11												
12	**NPV of Project / Total Revenue Requirements**	**0.58%**										
13												
14												
15	**Regulatory Assumptions**											
16	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
17	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
18	Equity Return		9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
19	Debt Return		6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
20	AFUDC		6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%
21												
22												
23	**Capital Cost**											
24	Capital Investment		551	15,992	19,627	0	0	0	0	0	0	0
25	Incremental meter costs		0	110	97	79	61	62	62	61	60	59
26	Avoided Itron Purchase (2013 & 2018)		0	0	0	0	0	(250)	0	0	0	0
27	AFUDC		17	500	613							
28	Total Construction Cost in Year		568	16,602	20,337	79	61	(188)	62	61	60	59
29	Cumulative Construction Cost		568	17,170	37,507	37,586	37,647	37,459	37,521	37,583	37,642	37,701
30	Land											
31	Net Cost of Removal											
32	Total Capital Cost in Year		568	16,602	20,337	79	61	(188)	62	61	60	59
33	Cumulative Capital Cost		568	17,170	37,507	37,586	37,647	37,459	37,521	37,583	37,642	37,701

10	15	16	17	18	19	20	21	22	23	24	25
Dec-18	**Dec-23**	**Dec-24**	**Dec-25**	**Dec-26**	**Dec-27**	**Dec-28**	**Dec-29**	**Dec-30**	**Dec-31**	**Dec-32**	**Dec-33**
(3,327)	(3,735)	(3,910)	(4,092)	(4,256)	(4,442)	(4,635)	(4,837)	(5,048)	(5,269)	(5,484)	(5,725)
2,068	2,086	2,089	1,764	992	2,326	2,329	2,331	2,333	2,335	2,338	2,340
1,116	360	208	621	1,821	2,446	2,274	2,103	1,931	1,760	1,588	1,416
409	608	624	605	557	1,182	1,177	1,167	1,147	1,125	1,102	1,085
266	(682)	(990)	(1,102)	(886)	1,513	1,145	764	363	(48)	(457)	(884)
324,000	357,700	364,900	372,200	379,600	387,200	394,900	402,800	410,900	419,100	427,500	436,100
0.08%	-0.19%	-0.27%	-0.30%	-0.23%	0.39%	0.29%	0.19%	0.09%	-0.01%	-0.11%	-0.20%
40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%
0	0	0	0	0	0	0	0	0	0	0	0
57	49	47	46	34	34	34	34	35	35	35	35
(250)	(250)	0	0	0	0	(250)	0	0	0	0	(250)
(193)	(201)	47	46	34	34	(216)	34	35	35	35	(215)
37,507	37,518	37,565	37,611	37,645	37,679	37,463	37,497	37,532	37,566	37,601	37,387
(193)	(201)	47	46	34	34	(216)	34	35	35	35	(215)
37,507	37,518	37,565	37,611	37,645	37,679	37,463	37,497	37,532	37,566	37,601	37,387

Additions to Plant in Service	0	17,170	20,337	79	61	(188)	62	61	60	59
Cummulative Additions to Plant	0	17,170	37,507	37,586	37,647	37,459	37,521	37,583	37,642	37,701
CWIP	568	0	0	0	0	0	0	0	0	0
Annual Operating Costs / (Savings)										
Savings										
Annual Meter Reading Savings	-	-	(592)	(2,491)	(2,610)	(2,736)	(2,856)	(2,992)	(3,132)	(3,279)
Annual Customer Service Savings	-	-	(71)	(295)	(303)	(312)	(320)	(329)	(338)	(347)
Annual Operations Savings	-	-	-	(318)	(329)	(340)	(351)	(363)	(375)	(387)
Costs										
Incremental Labour		-	148	296	304	314	323	333	343	353
Software Service Agreement		-	-	242	246	251	256	262	267	272
Communications		-	-	142	145	148	151	154	157	160
Equipment Replacements		-	-	48	49	50	51	52	53	54
Total Incremental Operating Costs (Savings)	0	0	(516)	(2,377)	(2,497)	(2,624)	(2,746)	(2,883)	(3,026)	(3,174)
Depreciation Expense										
Opening Cash Outlay	0	0	17,170	37,507	37,586	37,647	37,459	37,521	37,583	37,642
Additions in Year	0	17,170	20,337	79	61	(188)	62	61	60	59
Cumulative Total	0	17,170	37,507	37,586	37,647	37,459	37,521	37,583	37,642	37,701
Depreciation Rate - composite average	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%
Depreciation Expense	0	0	761	1,662	1,665	1,668	1,660	1,662	1,665	1,668
Net Book Value										
Gross Property	0	19,864	42,840	42,919	42,980	43,042	43,104	43,165	43,225	43,283
Accumulated Depreciation	0	0	(3,106)	(8,541)	(13,982)	(18,064)	(21,151)	(23,207)	(25,267)	(27,332)
Net Book Value	0	19,864	39,734	34,377	28,998	24,978	21,952	19,958	17,957	15,952
Depreciation Expense - Meters										
Opening Cash Outlay	0	0	10,593	30,576	30,655	30,716	30,778	30,840	30,901	30,961
Additions in Year	0	10,593	19,983	79	61	62	62	61	60	59
Cumulative Total	0	10,593	30,576	30,655	30,716	30,778	30,840	30,901	30,961	31,020
Depreciation Rate - composite average	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
Depreciation Expense	0	0	706	2,038	2,044	2,048	2,052	2,056	2,060	2,064
Net Book Value - Meters										
Gross Property	0	10,593	30,576	30,655	30,716	30,778	30,840	30,901	30,961	31,020
Accumulated Depreciation	0	0	(706)	(2,745)	(4,788)	(6,836)	(8,888)	(10,944)	(13,004)	(15,068)
Net Book Value	0	10,593	29,870	27,910	25,928	23,942	21,952	19,958	17,957	15,952

(193)	(201)	47	46	34	34	(216)	34	35	35	35	(215)
37,507	37,518	37,565	37,611	37,645	37,679	37,463	37,497	37,532	37,566	37,601	37,387
0	0	0	0	0	0	0	0	0	0	0	0
(3,430)	(4,263)	(4,450)	(4,644)	(4,822)	(5,021)	(5,229)	(5,446)	(5,672)	(5,907)	(6,138)	(6,395)
(357)	(406)	(417)	(427)	(437)	(447)	(458)	(469)	(480)	(492)	(504)	(516)
(399)	(36)	(37)	(38)	(39)	(40)	(41)	(43)	(44)	(45)	(47)	(48)
364	421	434	447	460	474	489	503	518	534	550	566
278	306	313	319	325	332	338	345	352	359	366	374
163	180	184	187	191	195	199	203	207	211	215	219
55	61	62	64	65	66	68	69	70	72	73	75
(3,327)	(3,735)	(3,910)	(4,092)	(4,256)	(4,442)	(4,635)	(4,837)	(5,048)	(5,269)	(5,484)	(5,725)
37,701	37,719	37,518	37,565	37,611	37,645	37,679	37,463	37,497	37,532	37,566	37,601
(193)	(201)	47	46	34	34	(216)	34	35	35	35	(215)
37,507	37,518	37,565	37,611	37,645	37,679	37,463	37,497	37,532	37,566	37,601	37,387
4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%	4.43%
1,670	1,671	1,662	1,664	1,666	1,668	1,669	1,660	1,661	1,663	1,664	1,666
43,340	43,600	43,648	58,526	78,543	78,577	78,611	78,645	78,680	78,715	78,750	78,785
(29,400)	(39,794)	(41,883)	(43,648)	(44,640)	(46,966)	(49,295)	(51,625)	(53,959)	(56,294)	(58,632)	(60,972)
13,940	3,806	1,764	14,878	33,903	31,611	29,316	27,020	24,721	22,420	20,118	17,813
31,020	31,288	31,337	31,384	46,263	66,280	66,313	66,347	66,382	66,416	66,451	66,486
57	49	47	14,878	20,017	34	34	34	35	35	35	35
31,076	31,337	31,384	46,263	66,280	66,313	66,347	66,382	66,416	66,451	66,486	66,521
6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
2,068	2,086	2,089	1,764	992	2,326	2,329	2,331	2,333	2,335	2,338	2,340
31,076	31,337	31,384	46,263	66,280	66,313	66,347	66,382	66,416	66,451	66,486	66,521
(17,136)	(27,531)	(29,620)	(31,384)	(32,376)	(34,702)	(37,031)	(39,362)	(41,695)	(44,031)	(46,368)	(48,708)
13,940	3,806	1,764	14,878	33,903	31,611	29,316	27,020	24,721	22,420	20,118	17,813

82	**Depreciation Expense - Computer Hardware**										
83	Opening Cash Outlay	0	0	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179
84	Additions in Year	0	5,179	0	0	0	0	0	0	0	0
85	Cumulative Total	0	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179
86	Depreciation Rate - composite average	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
87	Depreciation Expense	0	0	1,036	1,036	1,036	1,036	1,036	0	0	0
88											
89	**Net Book Value - Computer Hardware**										
90	Gross Property	0	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179
91	Accumulated Depreciation	0	0	(1,036)	(2,071)	(3,107)	(4,143)	(5,179)	(5,179)	(5,179)	(5,179)
92	Net Book Value	0	5,179	4,143	3,107	2,071	1,036	0	0	0	0
93											
94											
95	**Depreciation Expense - Computer Software**										
96	Opening Cash Outlay	0	0	4,092	7,085	7,085	7,085	7,085	7,085	7,085	7,085
97	Additions in Year	0	4,092	2,993	0	0	0	0	0	0	0
98	Cumulative Total	0	4,092	7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085
99	Depreciation Rate - composite average	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%
100	Depreciation Expense	0	0	1,364	2,361	2,361	998	0	0	0	0
101											
102	**Net Book Value - Computer Software**										
103	Gross Property	0	4,092	7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085
104	Accumulated Depreciation	0	0	(1,364)	(3,725)	(6,087)	(7,085)	(7,085)	(7,085)	(7,085)	(7,085)
105	Net Book Value	0	4,092	5,721	3,359	998	0	0	0	0	0
106											
107	**Carrying Costs on Average NBV**										
108	Return on Equity	0	358	1,075	1,337	1,143	974	847	756	684	612
109	Interest Expense	0	383	1,150	1,430	1,223	1,041	905	808	731	654
110	AFUDC	0	0	0	0	0	0	0	0	0	0
111	**Total Carrying Costs**	0	742	2,225	2,767	2,366	2,015	1,752	1,564	1,415	1,266
112											
113											
114	**Income Tax Expense**										
115	Combined Income Tax Rate	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
116											
117	**Income Tax on Equity Return**										
118	Return on Equity	0	358	1,075	1,337	1,143	974	847	756	684	612
119	Gross up for revenue (Return / (1- tax rate)	0	519	1,536	1,870	1,566	1,334	1,160	1,036	937	838
120	Income tax on Equity Return	0	161	461	533	423	360	313	280	253	226
121											
122	**Income Tax on Timing Differences**										
123	Depreciation Expense	0	0	3,106	5,435	5,441	4,082	3,088	2,056	2,060	2,064
124	Less: Capital Cost Allowance	0	1,400	4,231	5,206	4,368	3,645	3,040	2,555	2,148	1,807
125	Total Timing Differences	0	(1,400)	(1,125)	229	1,072	436	47	(499)	(88)	257

5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179
0	0	0	0	0	0	0	0	0	0	0	0
5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179
20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
0	0	0	0	0	0	0	0	0	0	0	0
5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179	5,179
(5,179)	(5,179)	(5,179)	(5,179)	(5,179)	(5,179)	(5,179)	(5,179)	(5,179)	(5,179)	(5,179)	(5,179)
0	0	0	0	0	0	0	0	0	0	0	0
7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085
0	0	0	0	0	0	0	0	0	0	0	0
7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085
33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%
0	0	0	0	0	0	0	0	0	0	0	0
7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085	7,085
(7,085)	(7,085)	(7,085)	(7,085)	(7,085)	(7,085)	(7,085)	(7,085)	(7,085)	(7,085)	(7,085)	(7,085)
0	0	0	0	0	0	0	0	0	0	0	0
539	174	100	300	880	1,182	1,099	1,016	933	850	767	684
577	186	107	321	941	1,264	1,175	1,087	998	909	821	732
0	0	0	0	0	0	0	0	0	0	0	0
1,116	360	208	621	1,821	2,446	2,274	2,103	1,931	1,760	1,588	1,416
27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
539	174	100	300	880	1,182	1,099	1,016	933	850	767	684
739	238	138	411	1,206	1,619	1,506	1,392	1,279	1,165	1,051	937
199	64	37	111	325	437	407	376	345	315	284	253
2,068	2,086	2,089	1,764	992	2,326	2,329	2,331	2,333	2,335	2,338	2,340
1,501	617	504	429	366	311	246	191	165	144	126	91
567	1,469	1,586	1,335	626	2,015	2,083	2,140	2,168	2,191	2,212	2,249

126	Gross up for tax (Total Timing Differences/(1-tax rate))	0	(2,030)	(1,608)	321	1,469	598	65	(683)	(120)	352
127	Income tax on Timing Differences	0	(629)	(482)	91	397	161	17	(184)	(32)	95
128											
129	**Total Income Tax**	0	(468)	(22)	624	820	521	331	95	221	321
130											
131											
132	**Capital Cost Allowance**										
133	Opening Balance - UCC	0	0	15,769	31,876	26,748	22,441	18,608	15,629	13,136	11,048
134	Additions	0	17,170	20,337	79	61	(188)	62	61	60	59
135	Subtotal UCC	0	17,170	36,107	31,955	26,810	22,253	18,670	15,691	13,196	11,107
136	Capital Cost Allowance Rate	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%
137	CCA on Opening Balance	0	0	2,572	5,200	4,363	3,661	3,035	2,550	2,143	1,802
138	CCA on Capital Expenditures (1/2 yr rule)	0	1,400	1,659	6	5	(15)	5	5	5	5
139	Total CCA	0	1,400	4,231	5,206	4,368	3,645	3,040	2,555	2,148	1,807
140	Ending Balance UCC	0	15,769	31,876	26,748	22,441	18,608	15,629	13,136	11,048	9,300

776	2,013	2,172	1,829	858	2,760	2,853	2,932	2,970	3,002	3,030	3,081
210	543	586	494	232	745	770	792	802	811	818	832
409	608	624	605	557	1,182	1,177	1,167	1,147	1,125	1,102	1,085
9,300	3,881	3,063	2,607	2,224	1,892	1,614	1,153	996	865	756	665
(193)	(201)	47	46	34	34	(216)	34	35	35	35	(215)
9,106	3,680	3,111	2,653	2,258	1,926	1,399	1,187	1,031	900	791	450
16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%	16.31%
1,517	633	500	425	363	309	263	188	163	141	123	108
(16)	(16)	4	4	3	3	(18)	3	3	3	3	(18)
1,501	617	504	429	366	311	246	191	165	144	126	91
7,605	3,063	2,607	2,224	1,892	1,614	1,153	996	865	756	665	359

33.0 Reference: Amended Mr. Hans Karow #10

Q33.1 The amended response suggests that with hourly meter recording capability, the AMI system would be transmitting information no less frequently than hourly. Please confirm that this is the case and explain why this is necessary (e.g., why couldn't the hourly "readings" be communicated back to the central repository once a day – i.e. daily readings?).

A33.1 Most AMI systems require more frequent than daily communication with the meter to ensure overall system integrity and for outage and restoration alarms. Although it may only transmit readings once per day, the meter frequently communicates with the AMI system to show it is working and that the power is on at the meter.

34.0 Reference: Amended Horizon Technologies Inc. #2

Q34.1 The amended response suggests that with daily readings there would be a maximum lag of one hour between consumption and meter reading. Please explain why, if the reading is done daily, the maximum lag isn't 23/24 hours (depending upon how defined). That is the maximum lag would be for the first hour immediately after the previous day's reading.

A34.1 FortisBC assumes that the reference should have been to Amended Horizon Technologies Inc. #1.2 rather than #2. This response is clarified as follows:

With hourly readings, there is a maximum time lag of one hour between consumption and a meter reading. Once the reading is obtained, it will take a maximum of 24 hours for the data to be received and processed by the MDMR and made accessible on the internet for a total of 25 hours. The maximum time lag for daily readings is 48 hours as indicated in the original response to Horizon IR No. 2 Q 1.2.

Project No. 3698493: Advanced Metering Infrastructure (AMI) Project
Requestor Name: Horizon Technologies
Information Request No: 3
To: FortisBC Inc.
Request Date: May 8, 2008
Response Date: May 22, 2008

1.0 Reference: Exhibit B-6, Pages 1, 2, 4

FortisBC notes in its cover letter to the amended AMI application that:

> **"*FortisBC maintains that the Original Application as submitted provides valuable enhancements to customer service while supporting the BC Energy Plan initiatives in a cost effective manner.*"[1] [emphasis added]**
>
> **. . .**
>
> **"*As a result of these discussions, FortisBC is of the opinion that additional benefits which provide further support for the BC Energy Plan should be provided with the addition of functionality not included as part of the Original Application.***
>
> ***Specifically, the BC Energy Plan states that utilities should "…research, develop and implement best practices in conservation and energy efficiency and to increase public awareness.*"[2] [emphasis added]**

FortisBC notes in its amended AMI application that:

> **"*These amendments support several policy actions within the BC Energy Plan including conservation requirements, cost effective DSM opportunities and the exploration of new rate structures that encourage energy efficiency and conservation.***
>
> ***FortisBC believes the enhancements in this amendment are in the best interest of customers, and offer more flexibility and support for the BC Energy Plan at a reasonable cost.*"[3] [emphasis added]**

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[1] Exhibit B-6, Page 1
[2] Exhibit B-6, Page 1 & 2
[3] Exhibit B-6, Page 4

Q1.1 Please provide a copy of 2007 Energy Plan

A1.1 A copy of the 2007 BC Energy Plan is provided as Horizon Appendix 1.1.

2.0 Reference: Exhibit B-10, Page 5

FortisBC notes that "*FortisBC agrees that any new facts arising out of Bill 15, as they relate to FortisBC and BC Hydro, should be subject to IRs.*"[4]

Q2.1 Please provide a copy of Bill 15 and confirm it has now passed Royal Assent – on May 1, 2008.

A2.1 A copy of Bill 15 – 2008 is provided as Horizon Appendix 2.1. Bill 15 – 2008 received Royal Assent on May 1, 2008.

3.0 Reference: Exhibit B-16, Section 1, Page 3 & Bill 15 – 2008 Utilities Commission Amendment, 2008:

FortisBC in its amended application states: "*On December 19, 2007 FortisBC filed an Application, pursuant to sections 45 and 46 of the Utilities Commission Act, for a Certificate of Public Convenience and Necessity (the "Original Application", Exhibit B-1) for the Advanced Metering Infrastructure ("AMI") Project.*"[5]

Bill 15 added the following to Section 46 of the Utilities Commission Act:

> **"*(3.1) In deciding whether to issue a certificate under subsection (3), the commission must consider***
>
> **(a) *the government's energy objectives, . . .*"[6]**

[4] Exhibit B-10, Page 5
[5] Exhibit B-6, Section 1, Page 3
[6] Bill 15, Item 9

The following definitions were added to Section 1 of Utilities Commission Act:

> **"*'government's energy objectives' means the following objectives of the government:***
> ***(a) to encourage public utilities to reduce greenhouse gas emissions;***
> ***(b) to encourage public utilities to take demand-side measures; . . .*"[7]**
>
> **"*'demand-side measure' means a rate, measure, action or program undertaken***
> ***(a) to conserve energy or promote energy efficiency,***
> ***(b) to reduce the energy demand a public utility must serve, or***
> ***(c) to shift the use of energy to periods of lower demand;*"[8]**

Q3.1 Please confirm that Bill 15 has changed section 46 of the Utilities Commission Act and those changes occurred after the AMI Application and the Amended AMI Application were submitted. Please confirm that it is a section in which the AMI application itself was developed from.

A3.1 Yes, Section 46 of the Utilities Commission Act has been amended by Bill 15. The Amended Application is consistent with Section 46.

Q3.2 Please comment on the reduction of greenhouse gas emission (GHG) as a consequence of the Advanced Metering Infrastructure to be delivered within the stated budget.

A3.2 The Original Application, Section 5.2 (Exhibit B-1), identified 217.6 tonnes of reduced GHG emissions annually as a result of the elimination of manual meter reading and the associated reduced vehicle usage.

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[7] Bill 15, Item 1
[8] Bill 15, Item 1

Q3.3 Please comment on the potential reduction of greenhouse gas emissions as a consequence of the Advanced Metering Infrastructure in the future (e.g. such as adding features such *"Innovative Rate Structures:, "Load Control", "Remote Disconnect / Reconnect", "Meter Reading Frequency", "Avoided Handheld Upgrades")*[9]. Please contribute potential reductions to specific features as listed above (e.g. Innovative Rate Structures could result in certain GHG reductions.)

A3.3 Additional GHG emission reductions may be associated with future initiatives that leverage the AMI system and contribute to reduced electricity consumption, however the amount of future GHG emission reductions resulting from electricity conservation attributable to the proposed AMI system depends upon:

- the amount of electricity consumption reduction attributable to the AMI system versus any additional expenditures on initiatives required to achieve that reduction; and
- the mix of energy being purchased by FortisBC at the time of the reduction.

Q3.4 Please comment on how demand-side measures (rate, measure, action, or program), as a consequence of the Advanced Metering Infrastructure to be delivered within the stated budge, will:

Q3.4.1 conserve energy or promote energy efficiency

Q3.4.2 reduce the energy demand a public utility must serve

Q3.4.3 shift the use of energy to periods of lower demand

A3.4 The Amended Application enables a variety of demand-side conservation measures, but implementation of those measures is not within the scope or cost estimates in the Amended Application. Please refer to the response to Horizon IR No. 3 Q3.5 for a discussion of future savings.

[9] Exhibit B-1, Section 4.1.3, Page 22-23

Q3.5 Please comment on how demand-side measures (rate, measure, action, or program), as a consequence of the Advanced Metering Infrastructure in the future (e.g. such as adding features "*Innovative Rate Structures", "Load Control", "Remote Disconnect / Reconnect", "Meter Reading Frequency", "Avoided Handheld Upgrades")*[10], *might:*

Q3.5.1 conserve energy or promote energy efficiency

Q3.5.2 reduce the energy demand a public utility must serve

Q3.5.3 shift the use of energy to periods of lower demand

Please refer to specific features as listed above (e.g. Innovative Rate Structures, through time-of-use could shift energy use by a certain percentage).

A3.5 FortisBC is of the opinion that innovative rate structures by themselves could shift between 2 and 5 percent of energy use to periods of lower demand. In-home displays showing consumption and rate information could reduce the range of uncertainly and bring the peak-shifted energy closer to 5 percent.

Load control devices could increase these percentages depending on the load being controlled, the degree to which it is controlled and whether the control is voluntary. The effect of load control devices alone on peak demand could be as low as 2 percent for minimal voluntary control, to as high as 25 percent for certain residential customers if load control was substantial and mandatory. Please also refer to the response to BCUC IR No. 3 Q38.4.2.

[10] Exhibit B-1, Section 4.1.3, Page 22-23

4.0 Reference: Exhibit B-9, Attachment A, Page 3 & Exhibit B-6, Section 1, Page 3:

The Ministry of Energy, Mines and Petroleum Resources (MEMPR) states in the March 31, 2008 letter to FortisBC:

> **"*Finally, the Ministry encourages FortisBC to develop a net metering tariff for residential and commercial customers . . .*"**[11] **[emphasis added]**

FortisBC in its amended AMI application states:

> ***"As compared to the Original Application, the following opportunities were identified:"***
>
> ***…***
>
> ***"• More flexibility in designing and adapting Time-of-Use and other innovative rates including Net Metering capabilities."***[12] **[emphasis added]**

FortisBC also states in response to an IR:

> **"*The Amended Application supports more aspects of the 'Smart Grid' concept including:*"**
>
> **…**
>
> **"*Support for net metering*"**[13] **[emphasis added]**

[11] Exhibit B-9, Attachment A, Page 3
[12] Exhibit B-6, Section 1, Page 3
[13] Exhibit B-6, Appendix B, BCUC Amended Response IR#2 A21.2

Q4.1 Please confirm that there will be support for Net Metering in the Advanced Metering Infrastructure to be delivered within the stated budget.

A4.1 Confirmed.

Q4.2 Please confirm that Net Metering should be included in the amended table listing the "*AMI Functions and Features*"[14]? Please confirm that it will be included as a "*Required*" function/feature?

A4.2 Net metering capability will be a requirement of the RFP as stated in the Amended Application Section 1, lines 15-16 (Exhibit B-6).

[14] Exhibit B-6, Section 4, Page 11

Q4.3 Please describe Net Metering in more detail, its relationship to the AMI project, and please explain how it furthers each of the "*government's energy objectives*"[15].

"*(a) to encourage public utilities to reduce greenhouse gas emissions;*

(b) to encourage public utilities to take demand-side measures;

(c) to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources;

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;

(e) to encourage public utilities to use innovative energy technologies

(i) that facilitate electricity self-sufficiency or the fulfillment of their long-term transmission requirements, or

***(ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy;*"[16]**

A4.3 "Net metering" is the principle where, during a given billing period, all energy consumed is netted against all energy generated and delivered back to the utility, and the balance is the amount billed. Net energy consumed may be charged at a different rate than net energy delivered. As discussed in response to Horizon IR No. 3 Q4.4 below, net metering can function separately and is not dependant on an AMI implementation.

Net metering, when restricted to generation from renewable sources, has benefits similar to other forms of distributed generation. Locating generation closer to load centers eases transmission congestion and reduces overall line

[15] Bill 15, Item 1
[16] Bill 15, Item 1

losses. Local generation may be viewed as equivalent to other DSM initiatives in that it reduces the amount of power required to be generated by utilities, and more therefore supplant the need to buy incremental power or construct new generation.

Q4.4 Please comment on whether the TOU, block and CPP pricing models will be available while using Net Metering[17]. Please discuss the relationships between the Net Metering and other functions/features[18]. Will these capabilities be included in the RFP as required to the vendors[19]?

A4.4 There is no technical barrier to making TOU, block and CPP rate structures available while using net metering. However, since FortisBC is currently developing a net metering tariff for approval by the BCUC, the availability to individual rates has yet to be determined. The net metering application is expected to be filed in the third quarter of 2008. The requirement for metering endpoint compatibility with net metering will be included in the RFP.

Q4.5 Please describe the next regulatory and consultation steps, including timing, to introduce Net Metering to FortisBC. Please clarify and comment on whether or not Net Metering is dependant on the AMI Project.

A4.5 These steps will be determined as FortisBC proceeds to develop its net metering policy. Net metering is not dependent on the AMI Project.

[17] Exhibit B-6, Section 4, Page 11
[18] Exhibit B-6, Section 4, Page 11
[19] Exhibit B-1, Section 7.1, Page 39

Q4.6 While the Information Technology Infrastructure is being updated for the AMI project, please discuss if there are any updates that could be done at that same time to lower the possible future costs of adding Net Metering.

A4.6 It is possible that the IT infrastructure will be enhanced to support net metering before implementation of AMI, and in any case there is not likely to be any significant savings associated with implementing the changes as part of the AMI project.

AMI will save future net metering hardware costs since the endpoints will be compatible with net metering. However, the amount of savings will depend upon the degree of customer participation.

Q4.7 Please indicate for all items discussed within this section, if they will be included in the criteria for the vendors[20]. If so, please indicate whether each is required or optional. If not, why not?

A4.7 Please see the response to Horizon IR No. 3 Q4.4.

[20] Exhibit B-1, Section 7.1, Pages 39-41 & Exhibit B-6, Section 4, Pages 10-11

5.0 Reference: Exhibit B-6, Section 1, Page 4

FortisBC notes that "*However, if the Commission does not approve the recommended enhancements, FortisBC respectfully submits that the Original Application as submitted on December 19, 2007, which still provides valuable enhancements to customer service while supporting the BC Energy plan initiatives in a cost effective manner, should be approved.*"[21]

Q5.1 Please clarify the process that FortisBC recommends for Intervenors who contend that the Original and Amended Applications are significantly different.

a) Should those Intervenors develop two complete sets of Evidence and Final Submissions to cover both situations (Original and Amended)

- or –

b) should those Intervenors develop their Evidence and Final Submission for the Amended Application, and if not approved, will have a final opportunity for Evidence and Final Submission for the Original Application?

A5.1 The regulatory timetable established by Order G-62-08 provides for a single Final Submission by Intervenors.

[21] Exhibit B-10, Page 5

6.0 Reference: Exhibit B-6, Section 2, Page 5:

FortisBC introduces the Home Area Network (HAN).

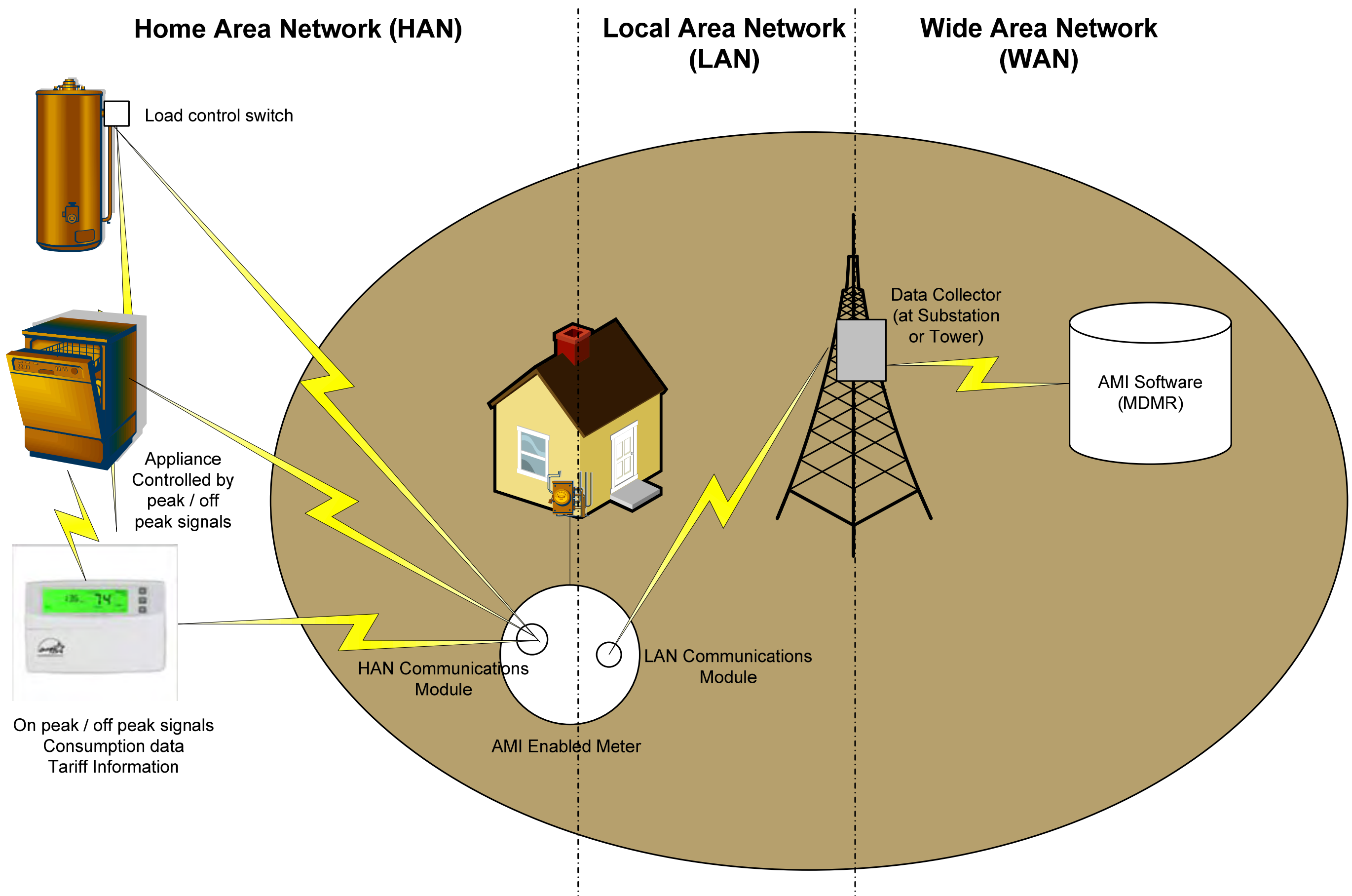
Q6.1 FortisBC indicates that the HAN "communicates with in-home display *devices . . .*"[22] It also states that "*this would enable FortisBC and its customers to control certain household appliances . . .*"[23]. FortisBC also indicates there will be "*. . . a communications component within the meter . .*"[24] Also, "*FortisBC will require a HAN that supports load controlling devices through the AMI-enabled meter and/or directly through the LAN communications infrastructure.*"[25]

Please elaborate on specifically how the HAN enables this. Please use a diagram to explain (similar to the diagram provided in Exhibit B-6, Appendix B, Horizon Amended Response IR#2 A4.1, Page 101), for a system in the future. In the diagram please include the meter (showing clearly the HAN and LAN communications components within the meter), in-home display device, household appliances, load controlling devices, HAN data communications link within the home, LAN data communications links connecting to outside the house, controller modules and any extra modules.

[22] Exhibit B-6, Section 2, Page 5
[23] Exhibit B-5, Section 2, Page 5
[24] Exhibit B-6, Appendix B, BCUC Amended Response IR#1 A1.2, Page 23
[25] Exhibit B-6, Appendix B, Horizon Amended Response IR#2 A4.1, Page 101

A6.1 Please see Figure A6.1 below illustrating the components listed above.

Figure A6.1: AMI Communications Network (HAN, LAN and WAN)



Q6.2 Using the same diagram developed above, please show clearly what will be delivered within the stated budget for this AMI Application.

A6.2 The components within the brown circle in Figure A6.1 are included within the stated budget.

Q6.3 Please specify all of the security measures planned to protect information and data communications.

A6.3 Vendors will be asked to specify the security protocols utilized within their AMI systems, and this will be evaluated against FortisBC internal hardware and software security requirements. These requirements include Advanced Encryption Standard (AES) 128, Institute of Electrical and Electronics Engineers (IEEE) 802.15.4 encryption at minimum.

Q6.4 FortisBC states "Display devices currently available range in functionality *from those that support simple visual indicators, such a green/red light indicators for on-peak/off peak periods, to those that can not only display consumption information, but also provide pricing information.*"[26]

Q6.4.1 Please discuss who would supply the display devices: FortisBC, AMI system vendor and/or 3rd party manufacturers. If FortisBC or the AMI system vendors are to suppliers in addition to 3rd party manufacturers, how would the 3rd party manufacturers be assured that they were not disadvantaged.

A6.4.1 Please see the response to BCUC IR No. 3 Q42.1. If FortisBC were to supply in-home devices to customers, it would likely engage in a competitive tendering process for the supply of such devices. This tendering process would not disadvantage any qualified third-party manufacturers.

[26] Exhibit B-6, Section 2, Page 5

Q6.4.2 Assuming 3rd party manufacturers are allowed to supply the display devices, please indicate if an "open standard" is to be used for the HAN data communications link? If so, please describe in detail the definition of "open standard" being used. If not, why not?

A6.4.2 FortisBC expects the HAN communication link to be an "open standard" but the detailed requirements around which standard(s) will be defined and evaluated through the RFP process.

Please comment on acceptable principles for the vendor of the HAN technology:

Q6.4.2.1 Royalties

e.g. will FortisBC be requiring the HAN protocol to be available royalty-free, or must any royalties be reasonable and non-discriminatory?

A6.4.2.1 FortisBC does not expect to charge any royalties related to the HAN protocol. If royalties were required, they would be reasonable and non-discriminatory.

Q6.4.2.2 Availability of obtaining the standard – including costs and timing of availability of versions

e.g. does FortisBC require the HAN specifications to be accessible to everyone free of charge, or is a nominal charge satisfactory?

e.g. must the entire specification be publicly available, or is it acceptable that members only can obtain latest versions?

A6.4.2.2 FortisBC does not expect to charge for the HAN specifications. If a charge was required, it would be reasonable and non-discriminatory. Details surrounding version control and how standards will be released to vendors have not yet been established and will be addressed at the time of implementation of those devices.

Q6.4.2.3 Discrimination as it relates to which manufacturers may develop the standards - including potential membership costs for developers

e.g. what does FortisBC consider acceptable restrictions on manufacturers developing product?

e.g. does FortisBC have any issues with large costs for standards membership?

A6.4.2.3 FortisBC intends to use open standards with respect to HAN communications. Any manufacturing restrictions on HAN-connected products would relate to ensuring that customers receive accurate, secure and reliable service from HAN devices. Membership fees have not been considered at this time.

Q6.4.2.4 Licensing requirements, intellectual property or other restrictions

e.g. will FortisBC be requiring world-wide nondiscriminatory conditions for licensing?

A6.4.2.4 Licensing requirements have not been considered at this time.

Q6.4.2.5 Quality and level of detail necessary for development e.g. must all standardized interfaces be revealed?

A6.4.2.5 The quality and level of detail necessary for HAN product development have not been considered at this time.

Q6.4.3 Please specify the type of information that would be available to these display devices, and the type of information that may reside in the meter but may not accessible to the display devices.

A6.4.3 FortisBC expects that at minimum, the customer's consumption information, current rate for electricity usage and pricing signals (in the case of TOU or CPP pricing) would be available to the in-home display. Any information provided by FortisBC and retained in a HAN-connected device (historical consumption data, for example) would be subject to requirements that ensure the security of that data.

Q6.4.4 Please specify the configuration methods for these display devices to allow connection to the meter. Would the display devices be able to connect to the meter without FortisBC's or the AMI vendor's involvement? If either involvement was needed, how would decisions be made on which devices would be allowed to connect?

A6.4.4 Only the inclusion of a HAN communications module is within the scope of the Amended Application. Detailed requirements regarding HAN-connected in-home displays, including issues around security and connectivity, will be addressed at the time of implementation of those devices.

Q6.4.5 Please provide the schedule for releasing of the HAN specifications of the AMI system for the use of 3rd party manufacturers.

A6.4.5 A schedule for releasing HAN specifications to third-party vendors would be determined after an RFP.

Q6.4.6 Please detail any verification and conformance testing schedules planned for 3rd party manufacturers. Please detail any pilots or testing programs expected.

A6.4.6 Schedules for verification and conformance testing of HAN devices would be determined after an RFP.

Q6.5 FortisBC states that: "This would enable FortisBC and its customers to control certain household appliances and subsequently reduce residential *loads during critical peak periods, if such capability was implemented in future.*"[27]

Please explain any differences for these controlling devices compared to display devices as discussed within Section 6.4 above.

A6.5 Simple in-home display units only display consumption information while more sophisticated units can act both as the in-home display and the control gateway to customer appliances. Alternatively, load controlling devices may be connected direct to HAN communications module in the meter (and not through the in-home display).

[27] Exhibit B-6, Section 2, Page 5

Q6.6 Please explain if the devices other than the meter, such as display devices and load control devices can operate with each other (without the meter).

A6.6 An example of devices operating with each other without the meter is described in the response to Horizon IR No 3 Q6.5.

Q6.7 Please comment on whether or not a gateway functionality will be included in the meter. Please comment on whether or not a gateway functionality can be included in a separate product. What would functions would be provided by the gateway.

A6.7 The meter is expected to serve only as a gateway for in-home display and load control units within the customers home.

Q6.8 Please indicate for all items discussed within this Section, 6.0, and all of its subsections, whether or not they will be included in the criteria for the vendors[28]. If so, please indicate whether each is required or optional. If not, why not?

A6.8 Detailed requirements such as those described in this Section 6.0 will be developed, defined and evaluated after approval of the Amended Application. Please also refer to the response to BCUC IR No. 3 Q46.1.

[28] Exhibit B-1, Section 7.1, Pages 39-41 & Exhibit B-6, Section 4, Pages 10-11

7.0 Reference: Exhibit B-6, Section 3, Page 6-9:

FortisBC discusses hourly readings in the AMI system.

Q7.1 FortisBC states: "Although the Amended Application includes TOU calculations Off Meter, it can also support calculations On Meter if *required.*"[29]

Q7.1.1 Please describe the situations in which "*On Mete*r" calculations would be required.

A7.1.1 On-meter calculations would be required if the AMI system was not designed to handle hourly readings or equipped with a VEE enabled MDMR.

Q7.1.2 Please indicate if all the TOU and CPP information for the resident and the tariff information will be available to the display devices. If so, please describe the path of information flow for "*Off Meter*" calculations. If not, why not?

A7.1.2 In-home display requirements relating to TOU and CPP rates would be defined during the planning and design of these rates in the future. It is likely that tariff information would be available to in-home display devices.

[29] Exhibit B-6, Section 3, Page 7

Q7.2 FortisBC states: "The increased bandwidth will reduce the latency for acquiring readings, make information available in more of a 'real-time *fashion' and have the potential to provide more immediate feedback to our customers on their energy use.*"[30]

Q7.2.1 Please clarify if the latency will also be reduced for the display devices and display on the Internet. If not, why not?

A7.2.1 Since the Original Application did not require HAN communications, no latency standard was defined for in-home displays. For details on the reduced latency of internet display, please see the response to BCOAPO IR No. 3 Q34.1.

Q7.2.2 Please discuss comparisons of latency for "*On Meter*" and "*Off Meter*" techniques[31].

A7.2.2 Latency for real-time consumption levels and peak / off peak period information would be comparable for both "On Meter" and "Off Meter" consumption calculations. This is the information available to customers on how much power is being used at any given time.

If the TOU bucket calculations were to be provided to the in-home display, the latency for "off meter" may be increased due to the time required to aggregate the TOU buckets in the MDMR. This is the information that would provide information on how much power was used during the billing period and would match to the customer's bill.

[30] Exhibit B-6, Section 3, Page 9
[31] Exhibit B-6, Section 3, Page 7

Q7.2.3 Please clarify how a "'real-time' fashion"[32] or "real-time display"[33] could be appropriate descriptions for a delay of "*25 hours*"[34].

A7.2.3 The reference to 25 hours relates to verified meter readings which will be available to customers over the internet. Please also see the response to BCOAPO IR No. 3 Q34.1. This is the information, indicating how much power was used during the billing period, would correlate with the information provided on the customer's bill.

The concept of "real-time" display relates to the in-home display capability of showing customers how much power is being consumed at any given time.

8.0 Reference: Exhibit B-6, Section 4, Page 11:

FortisBC includes a table of AMI functions and features as the criteria for vendors.

Q8.1 Please include a similar table of the functions and features for the HAN that would be used as criteria for vendors.

A8.1 Please see the response to Horizon IR No. 3 Q6.8.

Q8.2 Please describe the decision making process for the choice of the HAN technology.

A8.2 The decision making process for the HAN choice will be part of the overall RFP process in choosing the most appropriate AMI technology for FortisBC's requirements.

[32] Exhibit B-6, Section 3, Page 9
[33] Exhibit B-6, Appendix B, BCUC Amended Response IR#1 A1.2, Page 23
[34] Exhibit B-6, Appendix B, Horizon Amended Response IR#2 A1.2, Page 98

9.0 Reference: Exhibit B-6, Section 6, Page 13:

FortisBC lists the updated costs for the Amended Application.

Q9.1 Since the display device itself is not included in the Advanced Metering Infrastructure to be delivered within the stated budget, please indicate if the HAN module itself will be tested and verified in some manner. If so, please describe in detail what will be done, and costs involved. If not, please comment, why not, and the possible consequences?

A9.1 It is expected that the HAN capabilities will be tested as part of the RFP process as well as used in future DR pilots as described in the response to BCUC IR No. 3 Q38.4.1. The testing costs associated with the HAN are within the scope of the overall AMI system and are included within the project management and metering sections of the project costs.

10.0 Reference: Exhibit B-6, Appendix B, Horizon Amended Response IR#2 A1.3, Page 99:

FortisBC states "*Although not specified as a requirement in the Application, 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.*"[35]

Q10.1 Please clarify the definition of "*open standard*" that was used to answer this question.

A10.1 In this answer, an "open standard" was defined as a "publicly available specification controlled by a standards organization or a consortium".

[35] Exhibit B-6, Appendix B, Horizon Amended Response IR#2 A1.3, Page 99

Q10.2 Please discuss the ramifications of using a “*closed standard*”.

A10.2 FortisBC defines the term “closed standard” to mean “a specification controlled by a single organization”. Closed standards, or proprietary standards, would not be as desirable as compared to open standards if they resulted in a restriction of customer choice or HAN device portability without providing other benefits.

11.0 Reference: Bill 15 – 2008 Utilities Commission Amendment, 2008

Royal Assent was given for Bill 15 on May 1, 2008.

Q11.1 Does FortisBC agree with the following statement: “the act governing the regulatory body for FortisBC has changed with the Royal Assent given for Bill 15”? If not, why not.

A11.1 FortisBC agrees that the Utilities Commission Act has been amended by Bill 15, the “Utilities Commission Amendment Act, 2008”.

Q11.2 Does FortisBC agree with the following statement: “FortisBC will abide by Bill 15 immediately, and in support of that, will consider all aspects of Bill 15 in the AMI application”? If not, why not.

A11.2 FortisBC has considered its AMI Application in relation to Bill 15 and confirmed that no further amendments are required (see Exhibit B-9). Please also see the response to BCUC IR No. 3 Q51.3.1.

Q11.3 Please comment on all sections of Bill 15 which relate to the AMI application and describe all changes necessary to abide by Bill 15.

A11.3 Please see the response to BCUC IR No. 3 Q51.3.1 and Horizon IR No. 3 Q11.1 above.

12.0 Reference: AMI Application & Bill 15 – 2008 Utilities Commission Amendment, 2008

Q12.1 Does FortisBC agree with the following statement: "the Utilities Commission Act in place at the time of submitting the AMI application did not reference 'Greenhouse Gas Emissions' (GHGs) and the Utilities Commission Act now in effect (with the passing of Bill 15) does reference GHGs"?

A12.1 FortisBC agrees with this statement.

Q12.2 Before the passing of Bill 15, please comment on whether or not FortisBC was required to consider GHGs in the AMI application.

A12.2 Section 46(1) of the Utilities Commission Act [RSBC 1996] states that:

"An applicant for a certificate of public convenience and necessity must file with the commission information, material, evidence and documents that the commission prescribes."

The Commission's expectations are prescribed in the CPCN Application Guidelines (L-18-04), including in the requirements for the Project Description, section 2(iv) "identification and preliminary assessment of any impacts by the project on the physical, biological and social environments or on the public…, among which would be included the impact of GHGs.

Q12.3 After the passing of Bill 15, please comment on whether or not FortisBC agrees is now required to consider GHGs in the AMI application. If not, why not?

A12.3 Bill 15 does not state any such requirement of FortisBC. Section 46 of the Act as amended requires the Commission to consider the government's energy objectives in deciding whether to issue a CPCN.

The Commission's CPCN Application Guidelines have not changed since the passing of Bill 15 (please see the response to Horizon IR No. 3 Q12.2 above).

Q12.4 After the passing of Bill 15, please comment on whether or not FortisBC believes it should now consider GHGs in the AMI application. If not, why not?

A12.4 Section 5.2 of the Application (Exhibit B-1) discusses the AMI Project in connection with GHGs.

Q12.5 Please comment on whether or not FortisBC agrees that with the new Section 46(3.1a) of the Utilities Commission Act requires FortisBC to consider GHGs in the AMI application. If not, why not?

A12.5 Please see the response to BCUC IR No. 3 Q51.3.1 and Horizon IR No. 3 Q12.3 above.

Q12.6 With the passing of Bill 15, will FortisBC be adding a new section dealing with GHGs? If so, please provide the text for the section. If not, why not?

A12.6 Please see the response to Horizon IR No. 3 Q12.4 above.

Q12.7 Please comment on whether or not FortisBC agrees that the passing of Bill 15 translates to a fundamental change in the circumstances of the AMI application?

A12.7 No, FortisBC does not agree. Bill 15 provides a legislative framework for the provincial government's 2007 Energy Plan, support for which was a feature of the Original Application. In its letter of March 28, 2008 (Exhibit B-6), FortisBC stated that "additional benefits which provide further support for the BC Energy Plan should be provided with the addition of functionality not included as part of the Original Application". The passing of Bill 15 is not, in FortisBC's opinion, a "fundamental change in the circumstances" of the Application.

Q12.8 Please confirm that with Bill 15 passed, one of the "government's energy objectives"[36] is "to encourage public utilities to reduce greenhouse gas emissions"[37].

A12.8 Yes. This statement can be found in Section 1 of the Utilities Commission Amendment Act, 2008, found in Horizon Appendix 2.1.

13.0 Reference: Exhibit B-10, Reply, Page 3

FortisBC states "FortisBC and BC Hydro have been working and will continue to work together to ensure that where appropriate, technical requirements are aligned *and consistent between the two utilities.*"[38]

Q13.1 Please comment on how this alignment and consistency can be ensured if BC Hydro's implementation follows FortisBC's implementation.

A13.1 FortisBC understands that BC Hydro is engaged in an RFP process for their AMI system. As FortisBC has not yet completed an RFP, the timing is appropriate for both utilities to discuss functional requirements between the two systems.

Q13.2 Please clarify if BC Hydro's implementation might be limited, since BC Hydro follows FortisBC. If not, how is alignment and consistency ensured?

A13.2 Please see the response to Horizon IR No. 3 Q13.1.

[36] BC Government, Bill 15 – 2008 Utilities Commission Amendment, 2008; section 1
[37] BC Government, Bill 15 – 2008 Utilities Commission Amendment, 2008; section 1
[38] Exhibit B-10, Reply, Page 3

Q13.3 Please discuss the ramifications and risks that BC Hydro's implementation through Bill 15 might be mandated to be different than FortisBC.

A13.3 FortisBC believes that there is no risk that BC Hydro's implementation mandated by Bill 15 would be different than FortisBC's system in a way that FortisBC's system could not be enhanced to support in the future.

14.0 FortisBC states the following:

> **"FortisBC submits that the Amended AMI Application is consistent with and *supportive of the BC Energy Plan and Bill 15.*"[39]**

Q14.1 Please explain in detail the evidence to support this statement.

A14.1 The Amended Application and related IRs set out the support for Bill 15 as well as several policy actions within the BC Energy Plan including conservation requirements, cost effective DSM opportunities and exploration of new rate structures that encourage energy efficiency and conservation. Specifically:

- The AMI system reduces the number of vehicles required to perform billing functions and thereby reduces GHG emissions from those vehicles;
- The AMI system equipped with hourly readings, HAN and a VEE equipped MDMR creates the base functionality required to implement DSM and DR programs in the future;
- The hourly data provided by the AMI system will provide a cost-effective means of evaluating DSM and DR initiatives to ensure the best possible results are achieved;

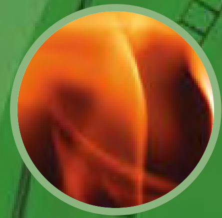
[39] Exhibit B-9, page 1

- The future addition of in-home displays through the HAN communications infrastructure will provide awareness to customers on their energy consumption levels and will assist them in making informed decisions when reducing their consumption; and
- The AMI system will support net metering.

In addition to the above points, the Ministry of Energy, Mines and Petroleum Resources (“MEMPR”) provided confirmation that the Amended Application was consistent with the BC Energy plan in their letter dated March 31st, 2008. Please see Attachment A in the Bill 15 response letter (Exhibit B-9).

Horizon Appendix 1.1







The BC Energy Plan

A Vision for Clean Energy Leadership

BRITISH COLUMBIA
The Best Place on Earth

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MESSAGE FROM THE PREMIER

The BC Energy Plan: A Vision for Clean Energy Leadership is British Columbia's plan to make our province energy self-sufficient while taking responsibility for our natural environment and climate. The world has turned its attention to the critical issue of global warming. This plan sets ambitious targets. We will pursue them relentlessly as we build a brighter future for B.C.

The BC Energy Plan sets out a strategy for reducing our greenhouse gas emissions and commits to unprecedented investments in alternative technology based on the work that was undertaken by the Alternative Energy Task Force. Most importantly, this plan outlines the steps that all of us – including industry, environmental agencies, communities and citizens – must take to reach these goals for conservation, energy efficiency and clean energy so we can arrest the growth of greenhouse gases and reduce human impacts on the climate.

As stewards of this province, we have a responsibility to manage our natural resources in a way that ensures they both meet our needs today and the needs of our children and grandchildren. We will all have to think and act differently as we develop innovative and sustainable solutions to secure a clean and reliable energy supply for all British Columbians.

Our plan will make B.C. energy self-sufficient by 2016. To do this, we must maximize our conservation efforts. Conservation will reduce pressure on our energy supply and result in real savings for those who use less energy. Individual actions that reduce our own everyday energy consumption will make the difference between success and failure. For industry, conservation can lead to an effective, productive and significant competitive advantage. For communities, it can lead to healthier neighbourhoods and lifestyles for all of us.

We are looking at how we can use clean alternative energy sources, including bioenergy, geothermal, fuel cells, water-powered electricity, solar and wind to meet our province's energy needs. With each of these new options comes the opportunity for new job creation in areas such as research, development, and production of innovative energy and conservation solutions. The combination of renewable alternative energy sources and conservation will allow us to pursue our potential to become a net exporter of clean, renewable energy to our Pacific neighbours.

Just as the government's energy vision of 40 years ago led to massive benefits for our province, so will our decisions today. **The BC Energy Plan** will ensure a secure, reliable, and affordable energy supply for all British Columbians for years to come.

Premier Gordon Campbell

MESSAGE FROM THE MINISTER

The BC Energy Plan: A Vision for Clean Energy Leadership is a made-in-B.C. solution to the common global challenge of ensuring a secure, reliable supply of affordable energy in an environmentally responsible way. In the next decade government will balance the opportunities and increased prosperity available from our natural resources while leading the world in sustainable environmental management.

This energy plan puts us in a leadership role that will see the province move to eliminating or offsetting greenhouse gas emissions for all new projects in the growing electricity sector, end flaring from oil and gas producing wells, and put in place a plan to make B.C. electricity self-sufficient by 2016.

In developing this plan, the government met with key stakeholders, environmental non-government organizations, First Nations, industry representatives and others. In all, more than 100 meetings were held with a wide range of parties to gather ideas and feedback on new policy actions and strategies now contained in **The BC Energy Plan**.

By building on the strong successes of Energy Plan 2002, this energy plan will provide secure, affordable energy for British Columbia. Today, we reaffirm our commitment to public ownership of our BC Hydro assets while broadening our supply of available energy.

We look towards British Columbia's leading edge industries to help develop new, greener generation technologies with the support of the new **Innovative Clean Energy Fund**. We're planning for tomorrow, today. Our energy industry creates jobs for British Columbians, supports important services for our families, and will play an important role in the decade of economic growth and environmental sustainability that lies ahead.

The Ministry of Energy, Mines and Petroleum Resources is responding to challenges and opportunities by delivering innovative, sustainable ways to develop British Columbia's energy resources.

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

In 2002, the Government of British Columbia launched an ambitious plan to invigorate the province's energy sector. Energy for Our Future: A Plan for BC was built around four cornerstones: low electricity rates and public ownership of BC Hydro; secure, reliable supply; more private sector opportunities; and environmental responsibility with no nuclear power sources. Today, our challenges include a growing energy demand, higher prices, climate change and the need for environmental sustainability. The BC Energy Plan: A Vision for Clean Energy Leadership builds on the successes of the government's 2002 plan and moves forward with new policies to meet the challenges and opportunities ahead.

- **Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.**
- **No nuclear power.**
- **Best coalbed gas practices in North America.**
- **Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.**

Environmental Leadership

The BC Energy Plan puts British Columbia at the forefront of environmental and economic leadership by focusing on our key natural strengths and our competitive advantages of clean and renewable sources of energy. The plan further strengthens our environmental leadership through the following key policy actions:

- **Zero greenhouse gas emissions from coal fired electricity generation.**
- **All new electricity generation projects will have zero net greenhouse gas emissions.**
- **Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.**

British Columbia's current electricity supply resources are 90 per cent clean and new electricity generation plants will have zero net greenhouse gas emissions.

A Strong Commitment to Energy Conservation and Efficiency

Conservation is integral to meeting British Columbia's future energy needs. The BC Energy Plan sets ambitious conservation targets to reduce the growth in electricity used within the province. British Columbia will:

- **Set an ambitious target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.**
- **Implement energy efficient building standards by 2010.**

Current per household electricity consumption for BC Hydro customers is about 10,000 Kwh per year. Achieving this conservation target will see electricity use per household decline to approximately 9,000 Kwh per year by 2020.

Energy Security

The Government of British Columbia is taking action to ensure that the energy needs of British Columbians continue to be met now and into the future. As part of ensuring our energy security, The BC Energy Plan sets the following key policy actions:

- **Maintain public ownership of BC Hydro and the BC Transmission Corporation.**
- **Maintain our competitive electricity rate advantage.**
- **Achieve electricity self-sufficiency by 2016.**
- **Make small power part of the solution through a set purchase price for electricity generated from projects up to 10 megawatts.**
- **Explore value-added opportunities in the oil and gas industry by examining the viability of a new petroleum refinery and petrochemical industry.**
- **Be among the most competitive oil and gas jurisdictions in North America.**
- **BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known.**

Investing in Innovation

British Columbia has a proven track record in bringing ideas and innovation to the energy sector. From our leadership and experience in harnessing our hydro resources to produce electricity, to our groundbreaking work in hydrogen and fuel cell technology, British Columbia has always met its future energy challenges by developing new, improved and sustainable solutions. To support future innovation and to help bridge the gap experienced in bringing innovations through the pre-commercial stage to market, government will:

- **Establish an Innovative Clean Energy Fund of $25 million.**
- **Implement the BC Bioenergy Strategy to take full advantage of B.C.'s abundant sources of renewable energy.**
- **Generate electricity from mountain pine beetle wood by turning wood waste into energy.**

Ambitious Energy Conservation and Efficiency Targets

The more energy that is conserved, the fewer new sources of supply we will require in the future. That is why British Columbia is setting new conservation targets to reduce growth in electricity demand.

Inefficient use of energy leads to higher costs and many environmental and security of supply problems.

Conservation Target

The BC Energy Plan sets an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020. This will require building on the "culture of conservation" that British Columbians have embraced in recent years.

The plan confirms action on the part of government to complement these conservation targets by working closely with BC Hydro and other utilities to research, develop, and implement best practices in conservation and energy efficiency and to increase public awareness. In addition, the plan supports utilities in British Columbia and the BC Utilities Commission pursuing all cost effective and competitive demand side management programs. Utilities are also encouraged to explore and develop rate designs to encourage efficiency, conservation and the development of renewable energy.

Future energy efficiency and conservation initiatives will include:

- Continuing to remove barriers that prevent customers from reducing their consumption.
- Building upon efforts to educate customers about the choices they can make today with respect to the amount of electricity they consume.
- Exploring new rate structures to identify opportunities to use rates as a mechanism to motivate customers either to use less electricity or use less at specific times.
- Employing new rate structures to help customers implement new energy efficient products and technologies and provide them with useful information about their electricity consumption to allow them to make informed choices.
- Advancing ongoing efforts to develop energy-efficient products and practices through regulations, codes and standards.

The average household uses about 10,000 kilowatt-hours of electricity per year.

POLICY ACTIONS

COMMITMENT TO CONSERVATION

- **Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.**
- **Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.**
- **Encourage utilities to pursue cost effective and competitive demand side management opportunities.**
- **Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.**

Implement Energy Efficiency Standards for Buildings by 2010

British Columbia implemented *Energy Efficient Buildings: A Plan for BC* in 2005 to address specific barriers to energy efficiency in our building stock through a number of voluntary policy and market measures. This plan has seen a variety of successes including smart metering pilot projects, energy performance measurement and labelling, and increased use of Energy Star appliances. In 2005, B.C. received a two year, $11 million federal contribution from the Climate Change Opportunities Envelope to support implementation of this plan.

Working together industry, local governments, other stakeholders and the provincial government will determine and implement cost effective energy efficiency standards for new buildings by 2010. Regulated standards for buildings are a central component of energy efficiency programs in leading jurisdictions throughout the world.

The BC Energy Plan supports reducing consumption by raising awareness and enhancing the efforts of utilities, local governments and building industry partners in British Columbia toward conservation and energy efficiency.

Aggressive Public Sector Building Plan

The design and retrofit of buildings and their surrounding landscapes offer us an important means to achieve our goal of making the government of British Columbia carbon neutral by 2010, and promoting Pacific Green universities, colleges, hospitals, schools, prisons, ferries, ports and airports.

British Columbia communities are already recognized leaders in innovative design practices. We know how to build smarter, faster and smaller. We know how to increase densities, reduce building costs and create new positive benefits for our environment. We know how to improve air quality, reduce energy consumption and make wise use of other resources, and how to make our landscapes and buildings healthy places for living, working and learning. We know how to make it affordable.

Government will set the following ambitious goals for all publicly funded buildings and landscapes and ask the Climate Action Team to determine the most credible, aggressive and economically viable options for achieving them:

- Require integrated environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
- Supply green, healthy workspaces for all public service employees.
- Capture the productivity benefits for people who live and work in publicly funded buildings such as reduced illnesses, less absenteeism, and a better learning environment.
- Aim not only for the lowest impact, but also for restoration of the ecological features of the surrounding landscapes.

Gigawatt = 1,000,000 kilowatts
Kilowatt = amount of power to light ten 100-watt incandescent light bulbs.

Community Action on Energy Efficiency

British Columbia is working in partnership with local governments to encourage energy conservation at the community level through the Community Action on Energy Efficiency Program. The program promotes energy efficiency and community energy planning projects, providing direct policy and technical support to local governments through a partnership with the Fraser Basin Council. A total of 29 communities are participating in the program and this plan calls for an increase in the level of participation and expansion of the program to include transportation actions. The Community Action on Energy Efficiency Program is a collaboration among the provincial ministries of Energy, Mines and Petroleum Resources, Environment, and Community Services, Natural Resources Canada, the Fraser Basin Council, Community Energy Association, BC Hydro, FortisBC, Terasen Gas, and the Union of BC Municipalities.

Leading the Way to a Future with Green Buildings and Green Cities

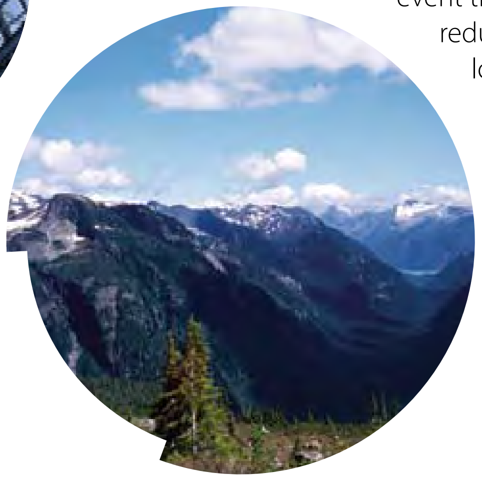
British Columbia has taken a leadership role in the development of green buildings. Through the Green Buildings BC Program, the province is working to reduce the environmental impact of government buildings by increasing energy and water efficiency and reducing greenhouse gas emissions. Through this program, and the Energy Efficient Buildings Strategy that establishes energy efficiency targets for all types of buildings, the province is inviting businesses, local governments and all British Columbians to do their part to increase energy efficiency and reduce greenhouse gas emissions.

The Green Cities Project sets a number of strategies to make our communities greener, healthier and more vibrant places to live. British Columbia communities are already recognized leaders in innovative sustainability practices, and the Green Cities Project will provide them with additional resources to improve air quality, reduce energy consumption and encourage British Columbians to get out and enjoy the outdoors. With the Green Cities Project, the provincial government will:

- Provide $10 million a year over four years for the new LocalMotion Fund, which will cost share capital projects on a 50/50 basis with municipal governments to build bike paths, walkways, greenways and improve accessibility for people with disabilities.
- Establish a new Green City Awards program to encourage the development and exchange of best practices by communities, with the awards presented annually at the Union of British Columbia Municipalities convention.
- Set new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.
- Commit to making new investments in expanded rapid transit, support for fuel cell vehicles and other innovations.

Industrial Energy Efficiency Program

Government will establish an Industrial Energy Efficiency Program for British Columbia to address challenges and issues faced by the B.C. industrial sector and support the Canada wide industrial energy efficiency initiatives. The program will encourage industry driven investments in energy efficient technologies and processes; reduce emissions and greenhouse gases; promote self generation of power; and reduce funding barriers that discourage energy efficiency in the industrial sector. Some specific strategies include developing a results based pilot program with industry to improve energy efficiency and reduce overall power consumption and promote the generation of renewable energy within the industrial sector.



The 2010 Olympic and Paralympics Games: Sustainability in Action

In 2010 Vancouver and Whistler will host the Winter Olympic and Paralympic Games. The 2010 Olympic Games are the first that have been organized based on the principles of sustainability.

All new buildings for the Olympics will be designed and built to conserve both water and materials, minimize waste, maximize air quality, protect surrounding areas and continue to provide environmental and community benefits over their lifetimes. Existing venues will be upgraded to showcase energy conservation and efficiency and demonstrate the use of alternative heating/cooling technologies. Wherever possible, renewable energy sources such as wind, solar, micro hydro, and geothermal energy will be used to power and heat all Games facilities.

Transportation for the 2010 Games will be based on public transit. This system – which will tie event tickets to transit use – will help reduce traffic congestion, minimize local air pollution and limit greenhouse gas emissions.

POLICY ACTIONS

BUILDING STANDARDS, COMMUNITY ACTION AND INDUSTRIAL EFFICIENCY

- **Implement Energy Efficiency Standards for Buildings by 2010.**
- **Undertake a pilot project for energy performance labelling of homes and buildings in coordination with local and federal governments, First Nations and industry associations.**
- **New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.**
- **Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.**
- **Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.**

British Columbia benefits from the public ownership of BC Hydro and the BC Transmission Corporation.

POLICY ACTIONS

SELF-SUFFICIENCY BY 2016

- **Ensure self-sufficiency to meet electricity needs, including "insurance."**
- **Establish a standing offer for clean electricity projects up to 10 megawatts.**
- **The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.**
- **Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.**
- **Ensure that the province remains consistent with North American transmission reliability standards.**

Electricity Security

Electricity, while often taken for granted, is the lifeblood of our modern economy and key to our entire way of life. Fortunately, British Columbia has been blessed with an abundant supply of clean, affordable and renewable electricity. But today, as British Columbia's population has grown, so too has our demand for electricity. We are now dependent on other jurisdictions for up to 10 per cent of our electricity supply. BC Hydro estimates demand for electricity to grow by up to 45 per cent over the next 20 years.

We must address this ever increasing demand to maintain our secure supply of electricity and the competitive advantage in electricity rates that all British Columbians have enjoyed for the last 20 years. There are no simple solutions or answers. We have an obligation to future generations to chart a course that will ensure a secure, environmentally and socially responsible electricity supply.

To close this electricity gap, and for our province to become electricity self-sufficient, will require an innovative electricity industry and the real commitment of all British Columbians to conservation and energy efficiency.

The New Relationship and Electricity

The Government of British Columbia is working with First Nations to restore, revitalize and strengthen First Nations communities. The goal is to build strong and healthy relationships with First Nations people guided by the principles of trust and collaboration. First Nations share many of the concerns of other British Columbians in how the development of energy resources may impact as well as benefit their communities. In addition, First Nations have concerns with regard to the recognition and respect of Aboriginal rights and title.

By focusing on building partnerships between First Nations, industry and government, tangible social and economic benefits will flow to First Nations communities across the province and assist in eliminating the gap between First Nations people and other British Columbians.

Government is working every day to ensure that energy resource management includes First Nations' interests, knowledge and values. By continuing to engage First Nations in energy related issues, we have the opportunity to share information and look for opportunities to facilitate First Nations' employment and participation in the electricity sectors to ensure that First Nations people benefit from the continued growth and development of British Columbia's resources. The BC Energy Plan provides British Columbia with a blueprint for facing the many energy challenges and opportunities that lay ahead. It provides an opportunity to build on First Nations success stories such as:

- First Nations involvement in independent power projects, such as the Squamish First Nation's participation in the Furry Creek and Ashlu hydro projects.

- Almost $4 million will flow to approximately 10 First Nations communities across British Columbia to support the implementation of Community Energy Action Plans as part of the First Nation and Remote Community Clean Energy Program.
- The China Creek independent power project was developed by the Hupacasath First Nation on Vancouver Island.

Achieve Electricity Self-Sufficiency by 2016

Achieving electricity self-sufficiency is fundamental to our future energy security and will allow our province to achieve a reliable, clean and affordable supply of electricity. It also represents a lasting legacy for future generations of British Columbians. That's why government has committed that British Columbia will be electricity self-sufficient within the decade ahead.

Through The BC Energy Plan, government will set policies to guide BC Hydro in producing and acquiring enough electricity in advance of future need. However, electricity generation and transmission infrastructure require long lead times. This means that over the next two decades, BC Hydro must acquire an additional supply of "insurance power" beyond the projected increases in demand to minimize the risk and implications of having to rely on electricity imports.

Small Power Standing Offer

Achieving electricity self-sufficiency in British Columbia will require a range of new power sources to be brought on line. To help make this happen, this policy will direct BC Hydro to establish a Standing Offer Program with no quota to encourage small and clean electricity producers. Under the Standing Offer Program, BC Hydro will purchase directly from suppliers at a set price. Eligible projects must be less than 10 megawatts in size and be clean electricity or high efficiency electricity cogeneration. The price offered in the standing offer contract would be based on the prices paid in the most recent BC Hydro energy call. This will provide small electricity suppliers with more certainty, bring small power projects into the system more quickly, and help achieve government's goal of maintaining a secure electricity supply. As well, BC Hydro will offer the same price to those in BC Hydro's Net Metering Program who have a surplus of generation at the end of the year.

Ensuring a Reliable Transmission Network

An important part of meeting the goal of self-sufficiency is ensuring a reliable transmission infrastructure is in place as additional power is brought on line. Transmission is a critical part of the solution as often new clean sources of electricity are located away from where the demand is. In addition, transmission investment is required to support economic growth in the province and must be planned and started in anticipation of future electricity needs given the long lead times required for transmission development. New and upgraded transmission infrastructure will be required to avoid congestion and to efficiently move the electricity across the entire power grid. Because our transmission system is part of a much larger, interconnected grid, we need to work with other jurisdictions to maximize the benefit of interconnection, remain consistent with evolving North American reliability standards, and ensure British Columbia's infrastructure remains capable of meeting customer needs.

BC HYDRO'S NET METERING PROGRAM: PEOPLE PRODUCING POWER

BC Hydro's Net Metering Program was established as a result of Energy Plan 2002. It is designed for customers with small generating facilities, who may sometimes generate more electricity than they require for their own use. A net metering customer's electricity meter will run backwards when they produce more electricity than they consume and run forward when they produce less than they consume.

The customer is only billed for their "net consumption"; the total amount of electricity used minus the total produced.

Net metering allows customers to lower their environmental impact and take responsibility for their own power production. It helps to move the province towards electricity self-sufficiency and expands clean electricity generation, making B.C.'s electricity supply more environmentally sustainable.

In order for British Columbia to ensure the development of a secure and reliable supply of electricity, **The BC Energy Plan** provides policy direction to the BC Transmission Corporation to ensure that our transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand. This will include ensuring there is adequate transmission capacity, ongoing investments in technology and infrastructure and remaining consistent with evolving North American reliability standards.

BC Transmission Corporation Innovation and Technology

As the manager of a complex and high-value transmission grid, BC Transmission Corporation is introducing technology innovations that provide improvements to the performance of the system and allow for a greater utilization of existing assets, ensuring B.C. continues to benefit from one of the most advanced energy networks in the world. BC Transmission Corporation's innovation program focuses on increasing the power transfer capability of existing assets, extending the life of assets and improving system reliability and security. Initiatives include:

- System Control Centre Modernization Project: This project is consolidating system operations into a new control center and backup site and upgrading operating technologies with a modern management system that includes enhancements to existing applications to ensure the electric grid is operating reliably and efficiently. The backup site will take over complete operation of the electric grid if the main site is unavailable.
- Real-Time Phasors: British Columbia is among the first North American jurisdictions to incorporate phasor measurement into control centre operations. Phasors are highly accurate voltage, current and phase angle "snapshots" of the real-time state of the transmission system that enable system operators to monitor system conditions and identify any impending problems.
- Real-Time Rating: This is a temperature monitoring system which enables the operation of two 500 kilovolt submarine cable circuits at maximum capacity without overloading. The resulting increase in capacity is estimated to be up to 10 per cent, saving millions of dollars.
- Electronic Temperature Monitor Upgrades for Station Transformers: In this program, existing mechanical temperature monitors will be replaced with newer, more accurate electronic monitors on station transformers that allow transformers to operate to maximum capacity without overheating. In addition to improving performance, BC Transmission Corporation will realize reduced maintenance costs as the monitors are "self-checking."
- Life Extension of Transmission Towers: BC Transmission Corporation maintains over 22,000 steel lattice towers and is applying a special composite corrosion protection coating to some existing steel towers to extend their life by about 25 years.

Public Ownership

Public Ownership of BC Hydro and the BC Transmission Corporation

BC Hydro and the BC Transmission Corporation are publicly-owned crown corporations and will remain that way now and into the future. BC Hydro is responsible for generating, purchasing and distributing electricity. The BC Transmission Corporation operates, maintains, and plans BC Hydro's transmission assets and is responsible for providing fair, open access to the power grid for all customers. Both crowns are subject to the review and approvals of the independent regulator, the BC Utilities Commission.

BC Hydro owns the heritage assets, which include historic electricity facilities such as those on the Peace and Columbia Rivers that provide a secure, reliable supply of low-cost power for British Columbians. These heritage assets require maintenance and upgrades over time to ensure they continue to operate reliably and efficiently. Potential improvements to these assets, such as capacity additions at the Mica and Revelstoke generating stations, can make important contributions for the benefit of British Columbians.

Confirming the Heritage Contract in Perpetuity

Under the 2002 Energy Plan, a legislated heritage contract was established for an initial term of 10 years to ensure BC Hydro customers benefit from its existing low-cost resources. With The BC Energy Plan, government confirms the heritage contract in perpetuity to ensure ratepayers will continue to receive the benefits of this low-cost electricity for generations to come.

British Columbia's Leadership in Clean Energy

The BC Energy Plan will continue to ensure British Columbia has an environmentally and socially responsible electricity supply with a focus on conservation and energy efficiency.

British Columbia is already a world leader in the use of clean and renewable electricity, due in part to the foresight of previous generations who built our province's hydroelectric dams. These dams - now British Columbians' 'heritage assets' - today help us to enjoy 90 per cent clean electricity, one of the highest levels in North America.

All New Electricity Generation Projects Will Have Zero Net Greenhouse Gas Emissions

The B.C. government is a leader in North America when it comes to environmental standards. While British Columbia is a province rich in energy resources such as hydro electricity, natural gas and coal, the use of these resources needs to be balanced through effective use, preserving our environmental standards, while upholding our quality of life for generations to come. The government has made a commitment that all new electricity generation projects developed in British Columbia and connected to the grid will have zero net greenhouse gas emissions. In addition, any new electricity generated from coal must meet the more stringent standard of zero greenhouse gas emissions.

POLICY ACTIONS

PUBLIC OWNERSHIP

- **Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.**
- **Establish the existing heritage contract in perpetuity.**
- **Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.**

POLICY ACTIONS

REDUCING GREENHOUSE GAS EMISSIONS FROM ELECTRICITY

- **All new electricity generation projects will have zero net greenhouse gas emissions.**
- **Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.**
- **Require zero greenhouse gas emissions from any coal thermal electricity facilities.**
- **Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.**
- **Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.**
- **No nuclear power.**

Zero Net Greenhouse Gas Emissions from Existing Thermal Generation Power Plants by 2016

Setting a requirement for zero net emissions over this time period encourages power producers to invest in new or upgraded technology. For existing plants the government will set policy around reaching zero net emissions through carbon offsets from other activities in British Columbia. It clearly signals the government's intention to continue to have one of the lowest greenhouse gas emission electricity sectors in the world.

Ensure Clean or Renewable Electricity Generation Continues to Account For at Least 90 per cent of Total Generation

Currently in B.C., 90 per cent of electricity is from clean or renewable resources. The BC Energy Plan commits to maintaining this high standard which places us among the top jurisdictions in the world. Clean or renewable resources include sources of energy that are constantly renewed by natural processes, such as water power, solar energy, wind energy, tidal energy, geothermal energy, wood residue energy, and energy from organic municipal waste.

Zero Greenhouse Gas Emissions from Coal

The government is committed to ensuring that British Columbia's electricity sector remains one of the cleanest in the world and will allow coal as a resource for electricity generation when it can reach zero greenhouse gas emissions. Clean-coal technology with carbon sequestration is expected to become commercially available in the next decade. Therefore, the province will require zero greenhouse gas emissions from any coal thermal electricity facilities which can be met through capture and sequestration technology. British Columbia is the first Canadian jurisdiction to commit to using only clean coal technology for any electricity generated from coal.

Burrard Thermal Generating Station

A decision regarding the Burrard Thermal Natural Gas Generating Station is another action that is related to environmentally responsible electricity generation in British Columbia.

Even though it could generate electricity from Burrard Thermal, BC Hydro imports power primarily because the plant is outdated, inefficient and costly to run. However, Burrard Thermal still provides significant benefits to BC Hydro as it acts as a "battery" close to the Lower Mainland, and provides extra capacity or "reliability insurance" for the province's electricity supply. It also provides transmission system benefits that would otherwise have to be supplied through the addition of new equipment at Lower Mainland sub-stations.

By 2014, BC Hydro plans to have firm electricity to replace what would have been produced at the plant. Government supports BC Hydro's proposal to replace the firm energy supply from Burrard Thermal with other resources by 2014. However, BC Hydro may choose to retain the plant for "reliability insurance" should the need arise.

No Nuclear Power

As first outlined in Energy Plan 2002, government will not allow production of nuclear power in British Columbia.

Benefits to British Columbians

Clean or renewable electricity comes from sources that replenish over a reasonable time or have minimal environmental impacts. Today, demand for economically viable, clean, renewable and alternative energy is growing along with the world's population and economies. Consumers are looking for power that is not only affordable but creates minimal environmental impacts. Fortunately, British Columbia has abundant hydroelectric resources, and plenty of other potential energy sources.

Maintain our Electricity Competitive Advantage

British Columbians require a secure, reliable supply of competitively priced electricity now and in the future. Competitively priced power is also an incentive for investors to locate in British Columbia. It provides an advantage over other jurisdictions and helps sustain economic growth. We are fortunate that historic investments in hydroelectric assets provide electricity that is readily available, reliable, clean and inexpensive. By ensuring public ownership of BC Hydro, the heritage assets and the BC Transmission Corporation and confirming the heritage contract in perpetuity, we will ensure that ratepayers continue to receive the benefits of this low cost generation. Due to load growth and aging infrastructure, new investments will be required. Investments in maintenance and in some cases expansions can be a cost effective way to meet growth and reduce future rate increases.

CARBON OFFSETS AND HOW THEY REDUCE EMISSIONS

A carbon offset is an action taken directly, outside of normal operations, which results in reduced greenhouse gas emissions or removal of greenhouse gases from the atmosphere. Here's how it works: if a project adds greenhouse gases to the atmosphere, it can effectively subtract them by purchasing carbon offsets which are reductions from another activity. Government regulations to reduce greenhouse gases, including offsets, demonstrate leadership on climate change and support a move to clean and renewable energy.

25

Government will establish a $25 million ***Innovative Clean Energy Fund.***

POLICY ACTIONS

BENEFITS TO BRITISH COLUMBIANS

- **Review BC Utilities Commissions' role in considering social and environmental costs and benefits.**
- **Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.**
- **Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.**
- **Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.**
- **Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.**

British Columbia must look for new, innovative ways to stay competitive. New technologies must be identified and nurtured, from both new and existing industries. By diversifying and strengthening our energy sector through the development of new and alternative energy sources, we can help ensure the province's economy remains vibrant for years to come.

Ensure Electricity is Secured at Competitive Prices

One practical way to keep rates down is to ensure utilities have effective processes for securing competitively priced power. As part of The BC Energy Plan, government will work with BC Hydro and parties involved to continue to improve the Call for Tender process for acquiring new generation. Fair treatment of both buyers and sellers of electricity will facilitate a robust and competitive procurement process. Government and BC Hydro will also look for ways to further recognize the value of intermittent resources, such as run-of- river and wind, in the acquisition process – which means that BC Hydro will examine ways to value separate projects together to increase the amount of firm energy calculated from the resources.

Rates Kept Low Through Powerex Trading of Electricity

Profits from electricity trade also contribute to keeping our electricity rates competitive. BC Hydro, through its subsidiary, Powerex, buys and sells electricity when it is advantageous to British Columbia's ratepayers. Government will continue to support capitalizing on electricity trading opportunities and will continue to allocate trade revenue to BC Hydro ratepayers to keep electricity rates low for all British Columbians.

BC Utilities Commissions' Role in Social and Environmental Costs and Benefits

The BC Energy Plan clarifies that social, economic and environmental costs are important for ensuring a suitable electricity supply in British Columbia. Government will review the BC Utilities Commissions' role in considering social, environmental and economic costs and benefits, and will determine how best to ensure these are appropriately considered within the regulatory framework.

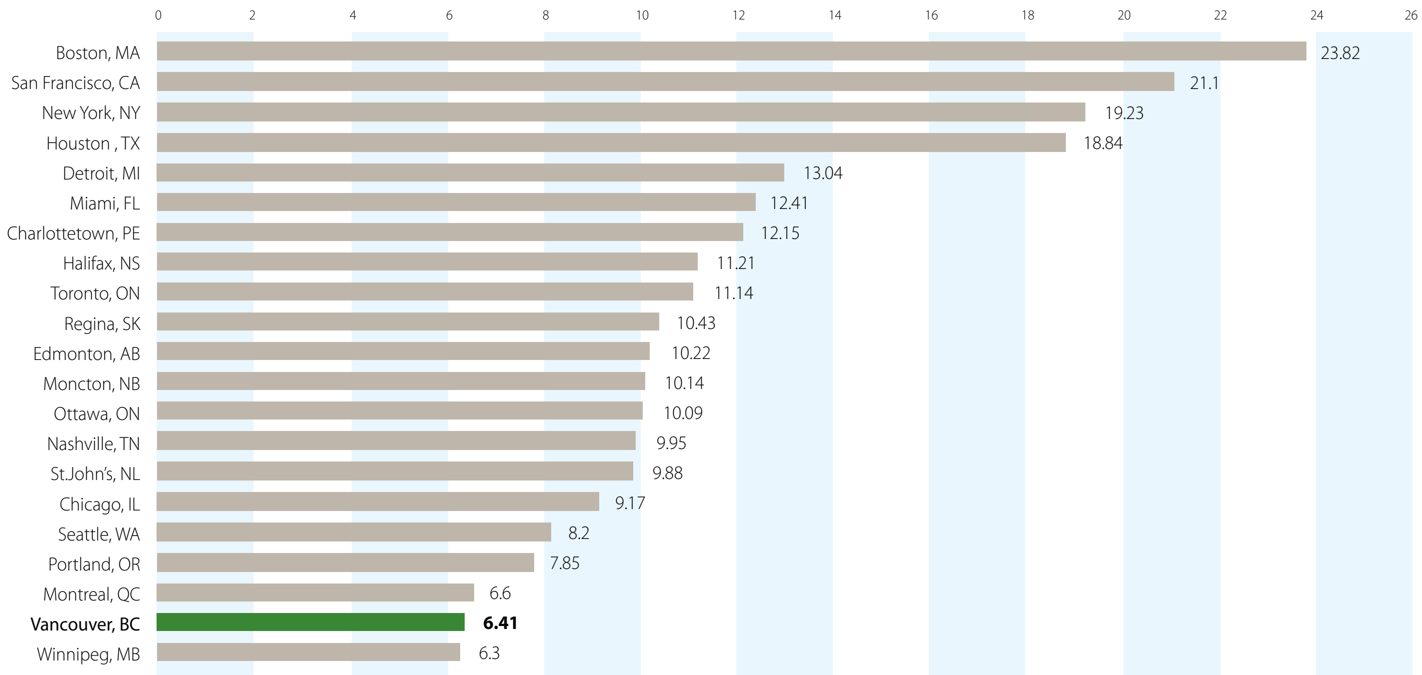
Bring Clean Power to Communities

British Columbia's electricity industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services. British Columbia's electricity industry already fosters economic development by implementing cost effective and reliable energy solutions in communities around the province. However, British Columbia covers almost one million square kilometres and electrification does not extend to all parts of our vast province.

Government and BC Hydro have established First Nation and remote community energy programs to implement alternative energy, energy efficiency, conservation and skills training solutions in a number of communities. The program focuses on expanding electrification services to as many as 50 remote and First Nations communities in British Columbia, enabling them to share in the benefits of a stable and secure supply of electricity. Government will put the policy framework in place and BC Hydro will implement the program over the next 10 years. The **Innovative Clean Energy Fund** can also support technological advancements to address the issue of providing a clean and secure supply of electricity to remote communities.

2006 Average Residential Electricity Price

Price (Canadian cents per kilowatt hour)



Source: Hydro Quebec comparison of Electricity Prices in Major North American Cities, April 2006

BRINGING CLEAN POWER TO ATLIN

Electricity in the remote community of Atlin in northwestern British Columbia is currently supplied by diesel generators. The First Nations and Remote Community Clean Energy Program is bringing clean power to Atlin.

The Taku Land Corporation, solely owned by the Taku River Tlingit First Nation will construct a two megawatt run-of-river hydroelectric project on Pine Creek, generating local economic benefits and providing clean power for Atlin. The Taku Land Corporation has entered into a 25 year Electricity Purchase Agreement with BC Hydro to supply electricity from the project to Atlin's grid. Over the course of the agreement, this will reduce greenhouse gas emissions by up to 150,000 tonnes as the town's diesel generators stand by.

The province is contributing $1.4 million to this $10 million project. This is the first payment from a $3.9 million federal contribution to British Columbia's First Nations and Remote Community Clean Energy Program. Criteria for federal funding included demonstrating greenhouse gas emissions reductions, cost-effectiveness, and partnerships with communities and industry.

Government will work with other agencies to maximize opportunities to develop, deploy and export British Columbia clean and alternative energy technologies.

POLICY ACTIONS

INVESTING IN INNOVATION

- **Establish the Innovative Clean Energy Fund to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.**
- **Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.**
- **Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.**

Innovative Clean Energy Fund

British Columbia's increasing energy requirements and our ambitious greenhouse gas emission reduction and clean energy targets require greater investment and innovation in the area of alternative energy by both the public and private sector.

To lead this effort, the government will establish an **Innovative Clean Energy Fund** of $25 million to help promising clean power technology projects succeed. The fund will be established through a small charge on energy utilities. The Minister of Energy, Mines and Petroleum Resources will consult with the energy utilities on the implementation of this charge.

Proponents of projects that will be supported through the fund will be encouraged to seek additional contributions from other sources. Government's new **Innovative Clean Energy Fund** will help make British Columbia a world leader in alternative energy and power technology. It will solve some of B.C.'s pressing energy challenges, protect our environment, help grow the economy, position the province as the place international customers turn to for key energy and environmental solutions, and assist B.C. based companies to showcase their products to world wide markets.

Following the advice of the Premier's Technology Council and the Alternative Energy and Power Technology Task Force, the fund will focus strictly on projects that:

- Address specific British Columbia energy and environmental problems that have been identified by government.
- Showcase B.C. technologies that have a strong potential for international market demand in other jurisdictions because they solve problems that exist both in B.C. and other jurisdictions.
- Support pre-commercial energy technology that is new, or commercial technologies not currently used in British Columbia.
- Demonstrate commercial success for new energy technologies.

Some problems that the fund could focus on include:

- Developing reliable power solutions for remote communities-particularly helping First Nations communities reduce their reliance on diesel generation for electricity.
- Advance conservation technologies to commercial application.
- Finding ways to convert vehicles to cleaner alternative fuels.
- Increasing the efficiency of power transmission through future grid technologies.
- Expanding the opportunities to generate power using alternative fuels (e.g.mountain pine beetle wood).

The British Columbia Bioenergy Strategy: Growing Our Natural Energy Advantage

Currently, British Columbia is leading Canada in the use of biomass for energy. The province has 50 per cent of Canada's biomass electricity generating capacity. In 2005, British Columbia's forest industry self-generated the equivalent of $150 million in electricity and roughly $1.5 billion in the form of heat energy. The use of biomass has displaced some natural gas consumption in the pulp and paper sector. The British Columbia wood pellet industry also enjoys a one-sixth share of the growing European Union market for bioenergy feedstock. The province will shortly release a bioenergy strategy that will build upon British Columbia's natural bioenergy resource advantages, industry capabilities and academic strength to establish British Columbia as a world leader in bioenergy development.

British Columbia's plan is to lead the bioeconomy in Western Canada with a strong and sustainable bioenergy sector. This vision is built on two guiding principles:

- Competitive, diversified forest and agriculture sectors.
- Strengthening regions and communities.

The provincial Bioenergy Strategy is aimed at:

- Enhancing British Columbia's ability to become electricity self-sufficient.
- Fostering the development of a sustainable bioenergy sector.
- Creating new jobs.
- Supporting improvements in air quality.
- Promoting opportunities to create power from mountain pine beetle-impacted timber.
- Positioning British Columbia for world leadership in the development and commercial adoption of wood energy technology.
- Advancing innovative solutions to agricultural and other waste management challenges.
- Encouraging diversification in the forestry and agriculture industries.
- Producing liquid biofuels to meet Renewable Fuel Standards and displace conventional fossil fuels.

Generating Electricity from Mountain Pine Beetle Wood: Turning Wood Waste into Energy

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant impact on forestry-based communities and industries, and heightens forest fire risk. There is a great opportunity to convert the affected timber to bioenergy, such as wood pellets and wood-fired electricity generation and cogeneration.

Through **The BC Energy Plan**, BC Hydro will issue a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.

MOUNTAIN PINE BEETLE INFESTATION: TURNING WOOD WASTE INTO ENERGY

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant economic impact on B.C.'s forestry industry and the many communities it helps to support and sustain. The forest fire risk to these communities has also risen as a result of their proximity to large stands of "beetle-killed" wood.

B.C. has developed a bioenergy strategy to promote new sources of sustainable and renewable energy in order to take advantage of the vast amounts of pine beetle-infested timber and other biomass resources. In the future, bioenergy will help meet our electricity needs, supplement conventional natural gas and petroleum supplies, maximize job and economic opportunities, and protect our health and environment.

The production of wood pellets is already a mature industry in British Columbia. Industry has produced over 500,000 tonnes of pellets and exported about 90 per cent of this product overseas in 2005, primarily to the European thermal power industry. Through **The BC Energy Plan**, BC Hydro will issue a call for proposals for further electricity generation from wood residue and mountain pine beetle-infested timber.

GOVERNMENT TO USE HYBRID VEHICLES ONLY

The provincial government is continuing the effort to reduce greenhouse gas emissions and overall energy consumption.

As part of this effort, government has more than tripled the size of its hybrid fleet since 2005 to become one of the leaders in public sector use of hybrid cars.

Hybrids emit much less pollution than conventional gas and diesel powered vehicles and thus help to reduce greenhouse gases in our environment. They can also be more cost-effective as fuel savings offset the higher initial cost.

As of 2007, all new cars purchased or leased by the B.C. government are to be hybrid vehicles. The province also has new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.

Addressing Greenhouse Gas Emissions from Transportation

The BC Energy Plan: A Vision for Clean Energy Leadership takes a first step to incorporate transportation issues into provincial energy policy. Transportation is a major contributor to climate change and air quality problems. It presents other issues such as traffic congestion that slows the movement of goods and people. The fuel we use to travel around the province accounts for about 40 per cent of British Columbia's greenhouse gas emissions. Every time we drive or take a vehicle that runs on fossil fuels, we add to the problem, whether it's a train, boat, plane or automobile. Cars and trucks are the biggest source of greenhouse gas emissions and contribute to reduced air quality in urban areas.

The government is committed to reducing greenhouse gas emissions from the transportation sector and has committed to adopting California's tailpipe emission standards from greenhouse gas emissions and champion the national adoption of these standards.

British Columbians want a range of energy options for use at home, on the road and in day-to-day life. Most people use gasoline or diesel to keep their vehicles moving, but there are other options that improve our air quality and reduce greenhouse gas emissions.

Natural gas burns cleaner than either gasoline or propane, resulting in less air pollution. Fuel cell vehicles are propelled by electric motors powered by fuel cells, devices that produce electricity from hydrogen without combustion.

GO GREEN

Cars that run on blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants. Electricity can provide an alternative to gasoline vehicles when used in hybrids and electric cars.

By working with businesses, educational institutions, non-profit organizations and governments, new and emerging transportation technologies can be deployed more rapidly at home and around the world. British Columbia will focus on research and development, demonstration projects, and marketing strategies to promote British Columbia's technologies to the world.

Implementing a Five Per Cent Renewable Fuel Standard for Diesel and Gasoline

The BC Energy Plan demonstrates British Columbia's commitment to environmental sustainability and economic growth by taking a lead role in promoting innovation in the transportation sector to reduce greenhouse gas emissions, improve air quality and help improve British Columbians' health and quality of life in the future. The plan will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry. It will further support the federal action of increasing the ethanol content of gasoline to five per cent by 2010. The plan will also see the adoption of quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions. These renewable fuel standards are a major component and first step towards government's goal of reducing the carbon intensity of all passenger vehicles by 10 per cent by 2020.

Government will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.

A Commitment to Extend British Columbia's Ground-breaking Hydrogen Highway

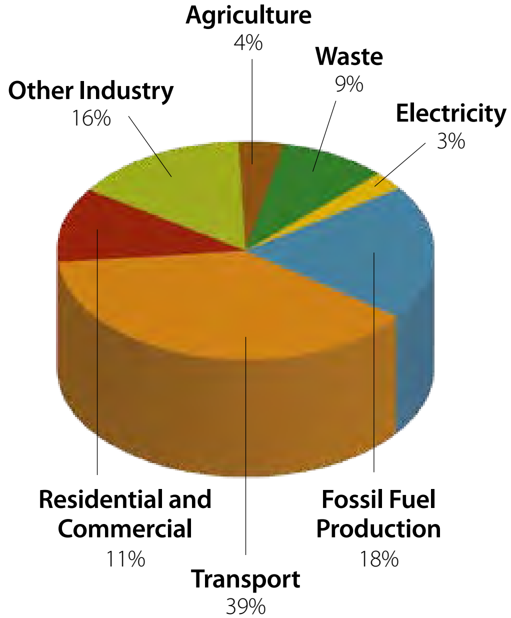
British Columbia is a world leader in transportation applications of the Hydrogen Highway, including the design, construction and safe operation of advanced hydrogen vehicle fuelling station technology. The Hydrogen Highway is a large scale, coordinated demonstration and deployment program for hydrogen and fuel cell technologies.

Vancouver's Powertech Labs established the world's first fast-fill, high pressure hydrogen fuelling station. The station anchors the Hydrogen Highway, which runs from Victoria through Surrey to Vancouver, North Vancouver, Squamish, and Whistler. Additional hydrogen fuelling stations are now in operation in Victoria and at the University of British Columbia.

The goal is to demonstrate and deploy various technologies and to one day see hydrogen filling stations around the province, serving drivers of consumer and commercial cars, trucks, and buses.

The unifying vision of the province's hydrogen and fuel cell strategy is to promote fuel cells and hydrogen technologies as a means of moving towards a sustainable energy future, increasing energy efficiency and reducing air pollutants and greenhouse gases. The Hydrogen Highway is targeted for full implementation by 2010. Canadian hydrogen and fuel cell companies have invested over $1 billion over the last five years, most of that in B.C. A federal-provincial partnership will be investing $89 million for fuelling stations and the world's first fleet of 20 fuel cell buses.

British Columbia will continue to be a leader in the new hydrogen economy by taking actions such as a fuel cell bus fleet deployment, developing a regulatory framework for micro-hydrogen applications, collaborating with neighbouring jurisdictions on hydrogen, and, in the long term, establishing a regulatory framework for hydrogen production, vehicles and fuelling stations.



B.C. Greenhouse Gas Emissions by Sector

(Based on 2004 data)
Source: Ministry of Environment

Cars and trucks are the biggest source of greenhouse gas emissions and reduce the quality of air in urban areas.

POLICY ACTIONS

ADDRESSING GREENHOUSE GAS EMISSIONS FROM TRANSPORTATION AND INCREASING INNOVATION

- **Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.**
- **Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.**
- **Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.**
- **Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.**

Vehicles that run on electricity, hydrogen and blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants.

LOCALMOTION FUND: REDUCING AIR POLLUTION IN YOUR COMMUNITY

The province has committed $40 million over four years to help build cycling and pedestrian pathways, improve safety and accessibility, and support children's activity programs in playgrounds.

This fund will help local government shift to hybrid vehicle fleets and help retrofit diesel vehicles which will help reduce air pollution and ensure vibrant and environmentally sustainable communities. This investment will also include expansion of rapid transit and support fuel cell vehicles.

Promote Energy Efficiency and Alternative Energy

It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. Working with municipalities, utilities and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province.

Environmental Leadership in Action

The BC Energy Plan: A Vision for Clean Energy Leadership complements other related cross-government initiatives that include supporting transportation demand management, reducing traffic congestion and better integrating land use and transportation planning. These plans include actions across a broad range of activities. Some key initiatives and recent announcements include:

- Extending the tax break on hybrid vehicle purchases beyond the current March 2008 deadline.
- Government to purchase hybrid vehicles exclusively.
- Reducing diesel emissions through new financial incentives to help municipalities shift to hybrid vehicle fleets and retrofit diesel vehicles with cleaner technologies.
- Green Ports:
  - Working with ports and the shipping sector to reduce emissions from their activities and marine vessels.
  - The Port of Vancouver has established idle reduction zones and has reduced truck emissions with its container reservation system which has reduced average wait times from two hours to approximately 20 minutes.
  - The port is also evaluating port-side electrification which would see vessels using shore-side electrical power while berthed rather than diesel power.
- Improving upon the monitoring and reporting of air quality information.
- Highway Infrastructure and Rapid Transit Infrastructure funding including the Gateway Program, the Border Infrastructure Program, high occupancy vehicle lanes, construction of the Rapid Transit Canada Line linking Richmond, the Vancouver International Airport and Vancouver, and the Rapid Transit Evergreen Line linking Burnaby to Coquitlam.
- Expanding the AirCare on the Road Program to the Lower Fraser Valley and other communities.
- Implementing the LocalMotion Program for capital projects to improve physical fitness and safety, reduce air pollution and meet the diverse needs of British Columbians.

A Choice of Electricity Options

The range of supply options, both large and small, for British Columbia include:

Bioenergy: Bioenergy is derived from organic biomass sources such as wood residue, agricultural waste, municipal solid waste and other biomass and may be considered a carbon-neutral form of energy, because the carbon dioxide released by the biomass when converted to energy is equivalent to the amount absorbed during its lifetime.

A number of bioenergy facilities operate in British Columbia today. Many of these are "cogeneration" plants that create both electricity and heat for on-site use and in some cases, sell surplus electricity to BC Hydro.

Reliability[1]: FIRM
Estimated Cost[5]: $75 – $91

Coal Thermal Power: The BC Energy Plan establishes a zero emission standard for greenhouse gas emissions from coal-fired plants. This will require proponents of new coal facilities to employ clean coal technology with carbon capture and sequestration to ensure there are no greenhouse gas emissions.

Reliability[1]: FIRM
Estimated Cost[5 6]: $67– $82

Geothermal: Geothermal power is electricity generated from the earth. Geothermal power production involves tapping into pockets of superheated water and steam deep underground, bringing them to the surface and using the heat to produce steam to drive a turbine and produce electricity. British Columbia has potential high temperature (the water is heated to more than 200 degrees Celsius) geothermal resources in the coastal mountains and lower temperature resources in the interior, in northeast British Columbia and in a belt down the Rocky Mountains. Geothermal energy's two main advantages are its consistent supply, and the fact that it is a clean, renewable source of energy.

Reliability[1]: FIRM
Estimated Cost[2]: $44 - $60

Hydrogen and Fuel Cell Technology:
British Columbia companies are recognized globally for being leaders in hydrogen and fuel cell technology for mobile, stationary and micro applications. For example, BC Transit's fuel cell buses are planned for deployment in Whistler in 2009.

Reliability[1]: FIRM
Estimated Cost[2]: n/a

[1] Reliability refers to energy that can be depended on to be available whenever required
[2] Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6
[3] Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions
[4] Based on a 250 MW combined cycle gas turbine plant. The BC Energy Plan requires coal power to meet zero GHG emissions
[5] Source: BC Hydro's F2006 Open Call for Power Report
[6] These costs do not reflect the costs of zero GHG emissions for coal thermal power

GOVERNMENT'S COMMITMENT TO THE ENVIRONMENT – THE ENVIRONMENTAL ASSESSMENT PROCESS

The environmental assessment process in British Columbia is an integrated review process for major projects that looks at potential environmental, community and First Nation, health and safety, and socioeconomic impacts. Through the environmental assessment process, the potential effects of a project are identified and evaluated early, resulting in improved project design and helping to avoid costly mistakes for proponents, governments, local communities and the environment.

An assessment is begun when a proposed project that meets certain criteria under the *Environmental Assessment Act* makes an application for an environmental assessment certificate. Each assessment will usually include an opportunity for all interested parties to identify issues and provide input; technical studies of the relevant environmental, social, economic, heritage and/or health effects of the proposed project; identification of ways to prevent or minimize undesirable effects and enhance desirable effects; and consideration of the input of all interested parties in compiling the assessment findings and making decisions about project acceptability. The review is concluded when a decision is made to issue or not issue an environmental assessment certificate. Industrial, mining, energy, water management, waste disposal, food processing, transportation and tourist destination resort projects are generally subject to an environmental assessment.

WHAT IS THE DIFFERENCE BETWEEN FIRM AND INTERMITTENT ELECTRICITY?

Firm electricity refers to electricity that is available at all times even in adverse conditions. The main sources of reliable electricity in British Columbia include large hydroelectric dams, and natural gas. This differs from intermittent electricity, which is limited or is not available at all times. An example of intermittent electricity would be wind which only produces power when the wind is blowing.

Large Hydroelectric Dams: The chief advantage of a hydro system is that it provides a reliable supply with both dependable capacity and energy, and a renewable and clean source of energy. Hydropower produces essentially no carbon dioxide.

Site C is one of many resource options that can help meet BC Hydro's customers' electricity needs. No preferred option has been selected at this time; however; it is recognized that the Province will need to examine opportunities for some large projects to meet growing demand.

As part of The BC Energy Plan, BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known. The purpose of this step is to engage the various parties up front to obtain input for the proposed engagement process. The decision-making process on Site C includes public consultation, environmental impact assessments, obtaining a Certificate of Public Convenience and Necessity, obtaining an Environmental Assessment Certificate and necessary environmental approvals, and approval by Cabinet.

Reliability[1]: FIRM
Estimated Cost[2]: $43 - $62

Natural Gas: Natural gas is converted into electricity through the use of gas fired turbines in medium to large generating stations; particularly high efficiencies can be achieved through combining gas turbines with steam turbines in the combined cycle and through reciprocating engines and mini and macro turbines. Combined cycle power generation using natural gas is the cleanest source of power available using fossil fuels. Natural gas provides a reliable supply with both dependable capacity and firm energy.

Reliability[1]: FIRM
Estimated Cost[2,6]: $48 - $100

Small Hydro: This includes run-of-river and micro Hydro. These generate electricity without altering seasonal flow characteristics. Water is diverted from a natural watercourse through an intake channel and pipeline to a powerhouse where a turbine and generator convert the kinetic energy in the moving water to electrical energy.

Twenty-nine electricity purchase agreements were awarded to small waterpower producers by BC Hydro in 2006. These projects will generate approximately 2,851 gigawatt hours of electricity annually (equivalent to electricity consumed by 285,000 homes in British Columbia). There are also 32 existing small hydro projects in British Columbia that generate 3,500 gigawatt hours (equivalent to electricity consumed by 350,000 homes in British Columbia).

Reliability[1]: INTERMITTENT
Estimated Cost[3]: $60 – $95

Solar: With financial support from the Ministry of Energy, Mines and Petroleum Resources, the "Solar for Schools" program has brought clean solar photovoltaic electricity to schools in Vernon, Fort Nelson, and Greater Victoria.

The BC Sustainable Energy Association is leading a project which targets installing solar water heaters on 100,000 rooftops across British Columbia.

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $700 - $1700

Tidal Energy: A small demonstration project has been installed at Race Rocks located west-southwest of Victoria. The Lester B. Pearson College of the Pacific, the provincial and federal government, and industry have partnered to install and test a tidal energy demonstration turbine at Race Rocks. The project will generate about 77,000 kilowatt hours on an annual basis (equivalent to electricity consumed by approximately eight homes).

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $100 - $360

Wind: British Columbia has abundant, widely distributed wind energy resources in three areas: the Peace region in the Northeast; Northern Vancouver Island; and the North Coast. Wind is a clean and renewable source that does not produce air or water pollution, greenhouse gases, solid or toxic wastes.

Three wind generation projects have been offered power purchase contracts in BC Hydro's 2006 Open Call for Power. These three projects will have a combined annual output of 979 gigawatt hours of electricity (equivalent to electricity consumed by 97,900 homes).

Reliability[1]: INTERMITTENT
Estimated Cost[5]: $71 – $74

[1] Reliability refers to energy that can be depended on to be available whenever required
[2] Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6
[3] Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions
[4] Based on a 250 MW combined cycle gas turbine plant.
[5] Source: BC Hydro's F2006 Open Call for Power Report
[6] These costs do not reflect the costs of zero net GHG emissions for natural gas

RACE ROCKS TIDAL ENERGY PROJECT

Announced in early 2005, this demonstration project between the provincial and federal governments, industry, and Pearson College is producing zero emission tidal power at the Race Rocks Marine Reserve on southern Vancouver Island. Using a current-driven turbine submerged below the ocean surface, the project is producing about 77,000 kilowatt hours of electricity per year, enough to meet the needs of approximately eight households. The knowledge gained about tidal energy will help our province remain at the forefront of clean energy generation technology.

Table 1: Summary of Resource Options

Description	Estimated Cost [1] $ /megawatt hour	Reliable[2]	Greenhouse gas emissions[3] tonnes per gigawatt hour
Energy conservation/ efficiency	32 – 76	Yes	0
Large hydroelectric	43 – 62	Yes	0
Natural gas	48 – 100 [8]	Yes	0 – 350 [4 8]
Coal	67 – 82 [9 10]	Yes	0 – 855 [5 9]
Biomass	75 – 91 [10]	Yes	0 – 500 [6]
Geothermal	44 – 60	Yes	0 – 10
Wind	71 – 74 [10]	Depends on the availability and speed of wind	0
Run-of-river small hydro	60 – 95 [10]	Depends on the flow of water, which varies throughout the year	0
Ocean (wave and tidal)	100 – 360 [7]	Future supply option which has great potential for British Columbia	0
Solar	700 – 1700 [7]	Depends on location, cloud cover, season, and time of day	0

1 Source: BC Hydro's 2006 Integrated Electricity Plan Volume 1 of 2, page 5-6
2 Reliability refers to energy that can be depended on to be available whenever required
3 Source: BC Hydro's 2006 Integrated Electricity Plan, Volume 2 of 2, Appendix F page 5-14 and Table 10-2
4 Based on a 250 MW combined cycle gas turbine plant
5 Based on a 500 MW supercritical pulverized coal combustion unit
6 GHG are 0 for wood residue and landfill gas. GHG is 500 tonnes per gigawatt hour for municipal solid waste
7 Source: BC Hydro's 2004 Integrated Electricity Plan, page 69
8 The BC Energy Plan requires natural gas plants to offset to zero net greenhouse gas emissions. These costs do not reflect the costs of zero net GHG emissions
9 The BC Energy Plan requires zero greenhouse gas emissions from any coal thermal electricity facilities
The costs do not include the costs of requiring zero emissions from coal thermal power
10 Source: BC Hydro's F2006 Open Call for Power Report

The majority of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation by all British Columbians and new electricity from independent power producers.

British Columbia's Strength in Electricity Diversity

British Columbia is truly fortunate to have a wide variety of future supply options available to meet our growing demand for energy. A cost effective way to meet that demand is to conserve energy and be more energy efficient. However, British Columbia will still need to bring new power on line to meet demand growth in the years ahead. In order to ensure we have this critical resource available to British Columbians when they need it, government will be looking to secure a range of made-in-B.C. power to serve British Columbians in the years ahead.

Government's goal is to encourage a diverse mix of resources that represent a variety of technologies. Some resource technologies, such as large and small hydro, thermal power, wind and geothermal provide well-established, commercially available sources of electricity. Other emerging technologies that are not yet widely used include large ocean wave and tidal power, solar, hydrogen and advanced coal technologies.

2004 Total Electricity Production by Source (% of total)

	Other Renewables	Hydro Electric	Nuclear	Waste and Biomass	Natural Gas	Diesel Oil	Coal	TOTAL
British Columbia	**0.0**	**92.8**	**0.0**	**1.0**	**6.0**	**0.2**	**0.0**	**100**
Alberta	2.3	4.4	0.0	0.0	12.0	2.6	78.7	100
Australia	0.3	6.9	0.0	0.6	12.3	0.70	79.2	100
California	10.7	17.0	14.5	0.0	37.7	0.0	20.1	100
Denmark	16.3	0.1	0.0	8.8	24.7	4.0	46.1	100
Finland	0.4	17.6	26.5	12.4	14.9	0.7	27.5	100
France	0.2	11.3	78.3	1.0	3.2	1.0	5.0	100
Germany	4.2	4.5	27.1	2.6	10.0	1.6	50.0	100
Japan	0.4	9.5	26.1	1.9	22.6	12.3	27.2	100
Norway	0.3	98.8	0.0	0.5	0.3	0.0	0.1	100
Ontario	1.8	24.8	49.7	0.0	5.2	0.5	18.0	100
Oregon	2.3	64.4	0.0	0.0	26.3	0.1	6.9	100
Quebec	0.7	94.5	3.2	0.0	0.1	1.5	0.0	100
United Kingdom	0.5	1.9	20.2	2.1	40.3	1.2	33.8	100
Washington	2.3	70.0	8.8	0.0	8.6	0.1	10.2	100

SHARING SOLUTIONS ON ELECTRICITY

The BC Energy Plan has a goal that most of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation and energy efficiency by all British Columbians, coupled with generation by independent power producers. However, these new projects take time to plan and implement. In addition, many of these sources provide limited amounts of firm supply. The province will also need to consider options for new, large scale sources to meet forecasted demand growth in the next 10 to 20 years. Large scale options could include Site C, large biomass facilities, clean coal or natural gas plants. As with all large scale undertakings, these kinds of projects will require years of lead time to allow for careful planning, analysis, consultation and construction.

Perhaps the biggest challenge facing British Columbians is simply to begin choosing our electricity future together. Demand for electricity is projected to grow by up to 45 per cent over the next 20 years. To meet this projected growth we will need to conserve more, and obtain more electricity from small power producers and large projects. Given the critical importance of public participation and stakeholder involvement in addressing the challenges and choices of meeting our future electricity needs, government and BC Hydro will seek and share solutions.

Rapid expansion of our energy sector means a growing number of permanent, well-paying employment opportunities are available.

Taking Action to Meet the Demand for Workers

The energy sector has been a major contributor to British Columbia's record economic performance since 2001. The BC Energy Plan focuses on four under-represented groups that offer excellent employment potential: Aboriginal people, immigrants, women and youth.

At the same time, the energy sector must overcome a variety of skills training and labour challenges to ensure future growth.

These challenges include:

- An aging workforce that upon retirement will leave a gap in experience and expertise.
- Competition for talent from other jurisdictions.
- Skills shortages among present and future workers.
- Labour market information gaps due to a lack of in-depth study.
- The need to coordinate immigration efforts with the federal government.
- The need for greater involvement of under-represented energy sector workers such as Aboriginal people, immigrants, women, and youth.
- A highly mobile workforce that moves with the opportunities.
- The need to improve productivity and enhance competitiveness.

Innovative, practical and timely skills training, and labour management is required to ensure the energy sector continues to thrive. As part of The BC Energy Plan, government will work collaboratively with industry, communities, Aboriginal people, education facilities, the federal government and others to define the projected demand for workers and take active measures to meet those demands.

Attract Highly Skilled Workers

Demographics show that those born at the height of the baby boom are retired or nearing retirement, leaving behind a growing gap in skills and expertise. Since this phenomenon is taking place in most western nations, attracting and retaining skilled staff is highly competitive.

To ensure continued energy sector growth, we need to attract workers from outside the province, particularly for the electricity, oil and gas, and heavy construction industries where the shortage is most keenly felt. At this time, a significant increase in annual net migration of workers from other provinces and from outside Canada is needed to complement the existing workforce.

Government and its partners are developing targeted plans to attract the necessary workers. These plans will include marketing and promoting energy sector jobs as a career choice.

Develop a Robust Talent Pool of Workers

It is vital to provide the initial training to build a job-ready talent pool in British Columbia, as well as the ongoing training employees need to adapt to changing energy sector technologies, products and requirements. We can ensure a thriving pool of talent in British Columbia by retraining skilled employees who are without work due to downturns in other industries. Displaced workers from other sectors and jurisdictions may require some retraining and new employees may need considerable skills development.

Another way to help ensure there are enough skilled energy sector workers in the years ahead is to educate and inform young people today. By letting high school students know about the opportunities, they can consider their options and make the appropriate training and career choices. Government will work to enhance information relating to energy sector activities in British Columbia's school curriculum in the years ahead.

Retain Skilled Workers

Around the world, energy facility construction and operations are booming, creating fierce, global competition for skilled workers. While British Columbia has much to offer, it is critical that our jurisdiction presents a superior opportunity to these highly skilled and mobile workers. That is why we need to ensure our workplaces are safe, fair and healthy and our communities continue to offer an unparalleled lifestyle with high quality health care and education, affordable housing, and readily available recreation opportunities in outstanding natural settings.

Inform British Columbians

To be effective in filling energy sector jobs with skilled workers, British Columbians need to be informed and educated about the outstanding opportunities available. As part of The BC Energy Plan, a comprehensive public awareness and education campaign based on sound labour market analysis will reach out to potential energy sector workers. This process will recognize and address both the potential challenges such as shift work and remote locations as well as the opportunities, such as obtaining highly marketable skills and earning excellent compensation.

Be Among the Most Competitive Oil and Gas Jurisdictions in North America

Since 2001, British Columbia's oil and gas sector has grown to become a major force in our provincial economy, employing tens of thousands of British Columbians and helping to fuel the province's strong economic performance. In fact, investment in the oil and gas sector was $4.6 billion in 2005. The oil and gas industry contributes approximately $1.95 billion annually or seven per cent of the province's annual revenues.

The BC Energy Plan is designed to take B.C.'s oil and gas sector to the next level to enhance a sustainable, thriving and vibrant oil and gas sector in British Columbia. With a healthy, competitive oil and gas sector comes the opportunity to create jobs and build vibrant communities with increased infrastructure and services, such as schools and hospitals. Of particular importance is an expanding British Columbia-based service sector.

There is a lively debate about the peak of the world's oil and gas production and the impacts on economies, businesses and consumers. A number of countries, such as the UK, Norway and the USA, are experiencing declining fossil fuel production from conventional sources. Energy prices, especially oil prices have increased and are more volatile than in the past. As a result, the way energy is produced and consumed will change, particularly in developed countries.

The plan is aimed at enhancing the development of conventional resources and stimulating activity in relatively undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources such as as tight gas, shale gas, and coalbed gas. The plan will further efforts to work with the federal government, communities and First Nations to advance offshore opportunities.

The challenge for British Columbia in the future will be to continue to find the right balance of economic, environmental and social priorities to allow the oil and gas sector to succeed, while protecting our environment and improving our quality of life.

The New Relationship and Oil and Gas

Working together with local communities and First Nations, the provincial government will continue to share in the many benefits and opportunities created through the development of British Columbia's oil and gas resources.

Government is working to ensure that oil and gas resource management includes First Nations' interests, knowledge and values. Government has recently concluded consultation agreements for oil and gas resource development with First Nations in Northeast British Columbia. These agreements increase clarity in the process and will go a long way to enhancing our engagement with these First Nations.

Government will continue to pursue opportunities to share information and look for opportunities to facilitate First Nations' employment and participation in the oil and gas industry to ensure that Aboriginal people benefit from the continued growth and development of British Columbia's resources.

POLICY ACTIONS

ENVIRONMENTALLY RESPONSIBLE OIL AND GAS DEVELOPMENT

- **Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.**
- **Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.**
- **Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.**
- **Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.**

The BC Energy Plan adopts a triple bottom line approach to competitiveness, with an attractive investment climate, environmentally sustainable development of B.C.'s abundant resources, and by benefiting communities and First Nations.

While striving to be among the most competitive oil and gas jurisdictions in North America, the province will focus on maintaining and enhancing its strong competitive environment for the oil and gas industry. This encompasses the following components:

- A competitive investment climate.
- An abundant resource endowment.
- Environmental responsibility.
- Social responsibility.

Leading in Environmentally and Socially Responsible Oil and Gas Development

The BC Energy Plan emphasizes conservation, energy efficiency, and the environmental and socially responsible management of the province's energy resources. It outlines government's efforts to meet this objective by working collaboratively with involved and interested parties, including affected communities, landowners, environmental groups, First Nations, the regulator (the Oil and Gas Commission), industry groups and others. Policy actions will support ways to address air emissions, impacts on land and wildlife habitat, and water quality.

The oil and gas sector in British Columbia accounts for approximately 18 per cent of greenhouse gas air emissions in the province. The main sources of air emissions from the oil and gas sector are flaring, fugitive gases, gas processing and compressor stations. While these air emissions have long been part of the oil and gas sector, they have also been a source of major concern for oil and gas communities.

Eliminate Flaring from Oil and Gas Producing Wells and Production Facilities By 2016

Through The BC Energy Plan, government has committed to eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011. In addition, government will adopt policies to reduce natural gas flaring and venting at test sites and pipelines, and encourage compressor station efficiency to cut back emissions. Government will also explore opportunities and new technologies for safe, underground disposal of carbon dioxide or sequestration from oil and gas facilities. Sequestration is considered a cost effective mitigation strategy in reducing carbon dioxide emissions.

Enhance Carbon Dioxide Sequestration in British Columbia

British Columbia is a member of the Plains CO2 Reduction (PCOR) Partnership composed of nearly 50 private and public sector groups from nine states and three Canadian provinces that is assessing the technical and economic feasibility of capturing and storing carbon dioxide emissions from stationary sources in western sedimentary basins.

B.C. is also a member of the West Coast Regional Carbon Sequestration Partnership, made up of west coast state and provincial government ministries and agencies. This partnership has been formed to pursue carbon sequestration opportunities and technologies.

To facilitate and foster innovation in sequestration, government will develop market oriented requirements with a graduated schedule. In consultation with stakeholders, a timetable will be developed along with increasing requirements for sequestration.

BRITISH COLUMBIA COMPANIES RECOGNIZED AS WORLD ENERGY TECHNOLOGY INNOVATORS

The leadership of British Columbian companies can be seen in all areas of the energy sector through innovative, industry leading technologies.

Production of a new generation of chemical injection pump for use in the oil and gas industry is beginning. The pumps, developed and built in British Columbia, are the first solar powered precision injection pumps available to the industry. They will reduce emissions by replacing traditional gas powered injection systems for pipelines.

Other solar technologies developed in British Columbia provide modular power supplies in remote locations all over the globe for marine signals, aviation lights and road signs.

Roads in B.C. and around the world are hosting demonstrations of fuel cell vehicles built with British Columbia technology. Thanks to the first high pressure hydrogen fuelling station in the world, compatible fuel cell vehicles in B.C. can carry more fuel and travel farther than ever before.

The Innovative Clean Energy Fund will help to build B.C.'s technology cluster and keep us at the forefront of energy technology development.

Government will work to improve oil and gas tenure policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval.

POLICY ACTIONS

OFFSHORE OIL AND GAS DEVELOPMENT

- **Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.**
- **Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.**
- **Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.**
- **Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.**

Environmental Stewardship Program

In 2004, the Ministry of Energy, Mines and Petroleum Resources initiated the Oil and Gas Environmental Stewardship Program having two components: the Environmental Policy Program and the Environmental Resource Information Project. The Environmental Policy Program identifies and mitigates environmental issues in the petroleum sector focusing on policy development in areas such as environmental waste management, habitat enhancement, planning initiatives, wildlife studies for oil and gas priority areas and government best management practices. Some key program achievements include the completion of guidelines for regulatory dispersion modeling, research leading to the development of soil quality guidelines for soluble barium, a key to northern grasses and their restorative properties for remediated well sites, and moose and caribou inventories in Northeast British Columbia.

The Environmental Resource Information Project is dedicated to increasing opportunities for oil and gas development, through the collection of necessary environmental baseline information. These projects are delivered in partnership with other agencies, industry, communities and First Nations.

The BC Energy Plan enhances the important Oil and Gas Environmental Stewardship Program. This will improve existing efforts to manage waste and preserve habitat, and will establish baseline data as well as development and risk mitigation plans for environmentally sensitive areas. Barriers need to be identified and steps taken for remediation, progressive reclamation, and waste management.

Best Coalbed Gas Practices in North America

Government will continue to encourage coalbed gas development with the intent of demonstrating that British Columbia is a leading socially and environmentally responsible coalbed gas developing jurisdiction. Coalbed gas, also known as coalbed methane, is natural gas found in coal seams. It is one of the cleanest burning of all fossil fuels. Proponents wanting to develop coalbed gas must adopt the following best practices:

- Fully engage local communities and First Nations in all stages of development.
- Use the most advanced technology and practices that are commercially viable to minimize land and aesthetic disturbances.
- Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
- Meet any other conditions the Oil and Gas Commission may apply.
- Demonstrate the company's previous experience with coalbed gas development, and information must be made publicly available as to how the company plans to meet and be accountable for these best practices.

Ensuring Offshore Oil and Gas Resources are Developed in a Scientifically Sound and Environmentally Responsible Way

The BC Energy Plan includes actions related to the province's offshore oil and gas resources. Since 1972, Canada and British Columbia have each had a moratorium in place on offshore oil and gas exploration and development. With advanced technology and

British Columbia's oil and gas industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services.

positive experiences in other jurisdictions, a compelling case exists for assessing British Columbia's offshore resource potential.

Government will work with coastal communities, First Nations, the federal government, environmental organizations, and others to ascertain the benefits and address the concerns associated with offshore oil and gas development.

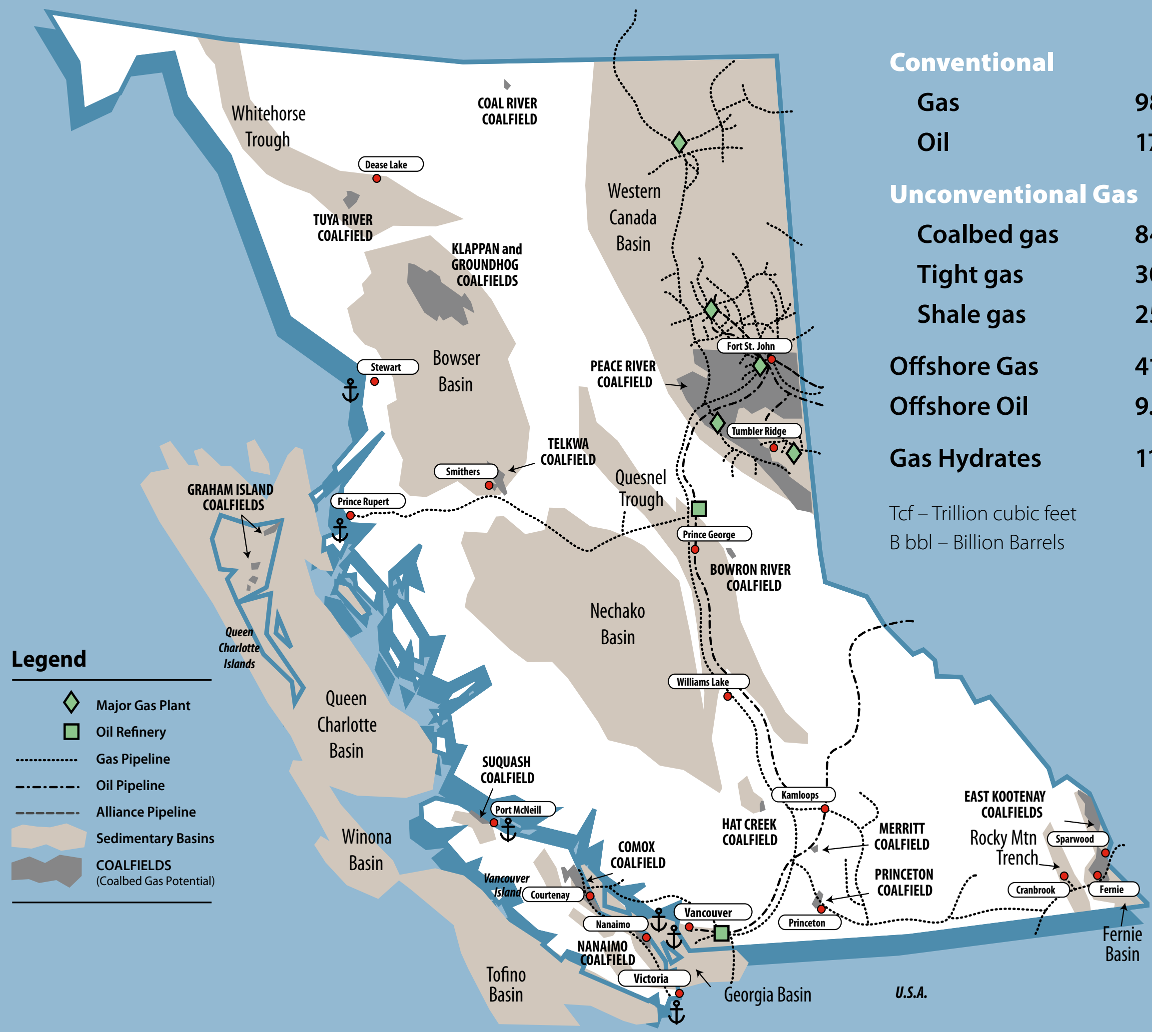
Maintaining B.C.'s Competitive Advantage as an Oil and Gas Jurisdiction

British Columbia's oil and gas industry is thriving thanks to high resource potential, industry and service sector expertise, and a competitive investment climate that includes a streamlined regulatory environment. To attract additional investment in British Columbia's oil and gas industry, we need to compete aggressively with other jurisdictions that may offer lower taxes or other investment incentives.

Another key way to be more competitive is by spurring activity in underdeveloped areas while heightening activity in the northeast, where our natural gas industry thrives. The province will work with industry to develop new policies and technologies for enhanced resource recovery making, it more cost-effective to develop British Columbia's resources.

By increasing our competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.

BC OIL AND GAS UNDISCOVERED RESOURCE ESTIMATES



Conventional	
Gas	98.0 Tcf
Oil	17.6 B bbl
Unconventional Gas	
Coalbed gas	84.0 Tcf
Tight gas	300 Tcf
Shale gas	250 Tcf
Offshore Gas	41.8 Tcf
Offshore Oil	9.8 B bbl
Gas Hydrates	113-847 Tcf

Tcf – Trillion cubic feet
B bbl – Billion Barrels

British Columbia's Enormous Natural Gas Potential

The oil and gas sector will continue to play an important role in British Columbia's future energy security. Our province has enormous natural gas resource potential and opportunities for significant growth. The BC Energy Plan facilitates the development of B.C.'s resources.

British Columbia has numerous sedimentary basins, which contain petroleum and natural gas resources. In north-eastern British Columbia, the Western Canada Sedimentary Basin is the focus of our thriving natural gas industry. The potential resources in the central and northern interior of the province, the Nechako and Bowser Basins and Whitehorse Trough, have gone untapped.

The delayed evaluation and potential development of these areas is largely due to geological and physical obstructions that make it difficult to explore in the area. Volcanic rocks that overlay the sedimentary package combined with complex basin structures, have hindered development.

The BC Energy Plan is aimed at enhancing the development of conventional resources and stimulating activity in undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources and take a more stringent approach on coalbed gas to meet higher environmental standards.

Attracting Investment and Developing our Oil and Gas Resources

The BC Energy Plan promotes competitiveness by setting out a number of important regulatory and fiscal measures including: monitoring British Columbia's competitive ranking, considering a Net Profit Royalty Program, promoting a B.C. service sector, harmonizing and streamlining regulations, and developing a Petroleum Registry to examine royalty and tenure incentives, and undertaking geoscience programs.

Establishment of a Petroleum Registry

The establishment of a petroleum registry that functions as a central database will improve the quality and management of key volumetric, royalty and infrastructure information associated with British Columbia's oil and gas industry and promote competition while providing transparency around oil and gas activity.

NEEMAC: SUCCESS THROUGH COMMUNICATION

As energy, mining and petroleum resource development increases in northeast B.C., so too does the need for input from local governments, First Nations, community groups, landowners and other key stakeholders. In 2006, the Northeast Energy and Mines Advisory Committee (NEEMAC) was created to provide an inclusive forum for representative organizations to build relationships with each other, industry and government to provide input on Ministry policy, and recommend innovative solutions to stakeholder concerns.

Since its creation, NEEMAC has identified and explored priority concerns, and is beginning to find balanced solutions related to environmental, surface disturbance, access and landowner rights issues. The Ministry is committed to implementing recommendations that represent the broad interests of community, industry and government and expects that the committee will continue to provide advice on energy, mining and petroleum development issues in support of The BC Energy Plan.

An opportunity to increase competitiveness exists in British Columbia's Interior Basins – namely the Nechako, Bowser and Whitehorse Basins – where considerable resource potential is known to exist.

Increasing Access

In addition to regulatory and fiscal mechanisms, the plan addresses the need for improving access to resources. Pipelines and road infrastructure are critical factors in development and competitiveness. The BC Energy Plan calls for new investment in public roads and other infrastructure. It will see government establish a clear, structured infrastructure royalty program, combining road and pipeline initiatives and increasing development in under-explored areas that have little or no existing infrastructure.

Developing Conventional and Unconventional Oil and Gas Resources

To support investment in exploration, The BC Energy Plan calls for partnerships in research and development to establish reliable regional data, as well as royalty and tenure incentives. The goal is to attract investment, create well-paying jobs, boost the regional economy and produce economic benefits for all British Columbians. We can be more competitive by spurring activity in underdeveloped areas while heightening activity in the northeast where our natural gas industry thrives. The plan advocates working with industry to develop new policies and technology to enhance resource recovery, including oil in British Columbia.

Improve Regulations and Research

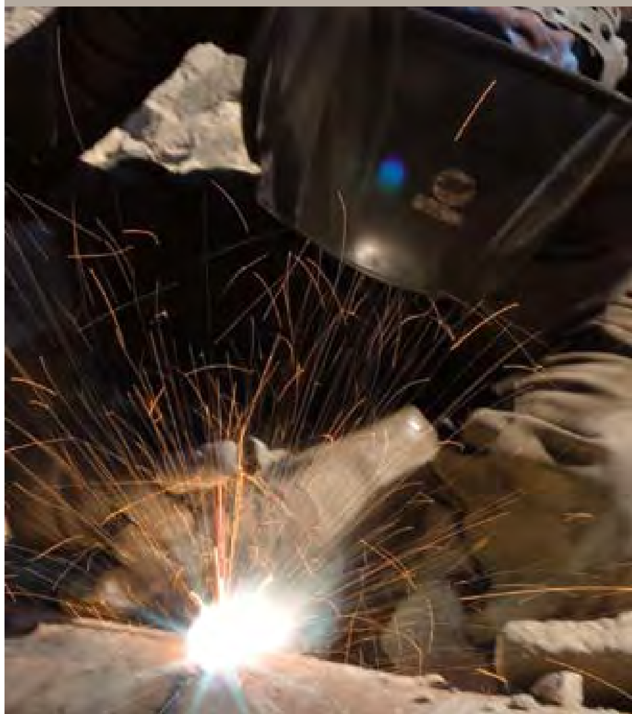
The province remains committed to continuous improvement in the regulatory regime and environmental management of conventional and unconventional oil and gas resources. The opportunities for enhancing exploration and production of tight gas, shale gas, and coalbed gas will also be assessed and supported by geoscience research and programs. The BC Energy Plan calls for collaboration with other government ministries, agencies, industry, communities and First Nations to develop the oil and gas resources in British Columbia.

Focus on Innovation and Technology Development

The BC Energy Plan also calls for supporting the development of new oil and gas technologies. This plan will lead British Columbia to become an internationally recognized centre for technological advancements and commercialization, particularly in environmental management, flaring, carbon sequestration and hydrogeology. The service sector has noted it can play an important role in developing and commercializing new technologies; however, the issue for companies is accessing the necessary funds.

THE HUB OF B.C.'S OIL AND GAS SECTOR

Oil and gas is benefiting all British Columbians - not just those living in major centres. Nowhere is this more apparent than in booming Fort St. John, which has rapidly become the oil and gas hub of the province. Since 2001, more than 1,400 people have moved to the community, an increase of 6.3 per cent and two per cent faster growth than the provincial average. Construction permits are way up - from $48.7 million in 2004, to $50.6 million in 2005, to over $123 million in 2006. In the past five years, over 1,000 new companies have been incorporated in Fort St. John, as young families, experienced professionals, skilled trades-people and many others move here from across the country.



POLICY ACTIONS

BE AMONG THE MOST COMPETITIVE OIL AND GAS JURISDICTIONS IN NORTH AMERICA

- **Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.**
- **Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.**
- **Encourage the development of conventional and unconventional resources.**
- **Support the growth of British Columbia's oil and gas service sector.**
- **Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.**
- **Encourage the development of new technologies.**
- **Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.**

Technology Transfer Incentive Program

A new Oil and Gas Technology Transfer Incentive Program will be considered to encourage the research, development and use of innovative technologies to increase recoveries from existing reserves and encourage responsible development of new oil and gas reserves. The program could recover program costs over time through increased royalties generated by expanded development and production of British Columbia's petroleum resources.

Scientific Research and Experimental Development

The BC Energy Plan supports the British Columbia Scientific Research and Experimental Development Program, which provides financial support for research and development leading to new or improved products and processes. Through credits or refunds, the expanded program could cover project costs directly related to commercially applicable research, and development or demonstration of new or improved technologies conducted in British Columbia that facilitate expanded oil and gas production.

Research and Development

The BC Energy Plan calls for using new or existing research and development programs for the oil and gas sector. Government will develop a program targeting areas in which British Columbia has an advantage such as well completion technology and hydrogeology.

A program to encourage oil and gas innovation and research in British Columbia's post-secondary institutions will be explored. These opportunities will be explored in partnership with the Petroleum Technology Alliance Canada and as part of the April 2006 Memorandum of Understanding between British Columbia and Alberta on Energy Research, Technology Development and Innovation.

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator, a site which provides innovators with space to build prototypes and carry out testing as well as providing business infrastructure and assistance accessing additional support will be established, allowing entrepreneurs to develop and test new innovations and commercialize new, innovative technologies and processes.

Nechako Initiative

The BC Energy Plan calls for government to partner with industry, the federal government, and Geoscience BC to undertake comprehensive research in the Nechako Basin and establish new data of the resource potential. It will include active engagement of communities and the development and implementation of a comprehensive pre-tenure engagement initiative for First Nations in the region. Specific tenures and royalties will be explored to encourage investment, as well as a comprehensive Environmental Information Program to identify baseline information needs in the area through consultations with government, industry, communities and First Nations.

By increasing our oil and gas industry's competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.

Value-Added Opportunities

To improve competitiveness, The BC Energy Plan calls for a review of value-added opportunities in British Columbia. This will include a thorough assessment of the potential for processing facilities and petroleum refineries as well as petrochemical industry opportunities. The Ministry of Energy, Mines and Petroleum Resources will conduct an analysis to identify and address barriers and explore incentives required to encourage investment in gas processing in British Columbia. A working group of industry and government will develop business cases and report to the Minister by January 2008 with recommendations on the viability of a new petroleum refinery and petrochemical industry and measures, if any, to encourage investment.

Oil and Gas Service Sector

British Columbia's oil and gas service sector can also help establish our province as one of the most competitive jurisdictions in North America. The service sector has grown over the past four years and with increased activity, additional summer drilling, and the security of supply, opportunities for local companies will continue. Government can help maximize the benefits derived from the service sector by:

- Promoting British Columbia's service sector to the oil and gas industry through participation at trade shows and providing information to the business community.
- Identifying areas where British Columbian companies can play a larger role, expand into other provinces, and through procurement strategies.

The government also supports the Oil and Gas Centre of Excellence at the Fort St. John Northern Lights College campus, which will provide oil and gas, related vocational, trades, career and technical programs.

Improving Oil and Gas Tenures

Government will work to improve oil and gas tenure issuance policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval by the end of 2007. This will provide clear parameters for industry regarding areas where special or enhanced management practices are required. These measures will strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into the oil and gas development process.

Create Opportunities for Communities and First Nations

Benefits for British Columbians from the Oil and Gas Sector

The oil and gas sector offers enormous benefits to all British Columbians through enhanced energy security, tens of thousands of good, well-paying jobs and tax revenues used to help fund our hospitals and schools. However, the day-to-day impact of the sector has largely been felt on communities and First Nations in British Columbia's northeast. Community organizations, First Nations, and landowners have communicated a desire for greater input into the pace and scope of oil and gas development in British Columbia.

OIL AND GAS

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator will be established, allowing entrepreneurs to develop and test new innovations.

Through **The BC Energy Plan**, government intends to develop stronger relationships with those affected by oil and gas development, including communities and First Nations. The aim is to work cooperatively to maximize benefits and minimize impacts. The plan supports improved working relationships among industry, local communities and landowners by increased and improved communication to clarify and simplify processes, enhancing dispute resolution methods, and offering more support and information.

The government will also continue to improve communications with local governments and agencies. Specifically, **The BC Energy Plan** calls for efforts to provide information about increased local oil and gas activities to local governments, education and health service providers to improve their ability to make timely decisions on infrastructure, such as schools, housing, and health and recreational facilities. By providing local communities and service providers with regular reports of trends and industry activities, they can more effectively plan for growth in required services and infrastructure.

POLICY ACTIONS

WORKING WITH COMMUNITIES AND FIRST NATIONS

- **Provide information about local oil and gas activities to local governments, First Nations, education and health service providers to inform and support the development of necessary social infrastructure.**
- **Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.**
- **Support First Nations in providing cross-cultural training to agencies and industry.**
- **Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.**
- **Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.**

Building Better Relationships with Landowners

The BC Energy Plan: A Vision for Clean Energy Leadership also supports improved working relationships between industry, local communities and landowners and First Nations. Landowners will be notified in a more timely way of sales of oil and gas rights on private land. Plain language information materials, including standardized lease agreements will be made available to help landowners deal with subsurface tenures and activity. There will be a review of the dispute resolution process between landowners and industry by the end of 2007. The existing setback requirements, the allowed distance of a well site from a residence, school or other public place, will also be examined. These measures seek to strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into oil and gas development.

Working in Partnership with First Nations and Communities

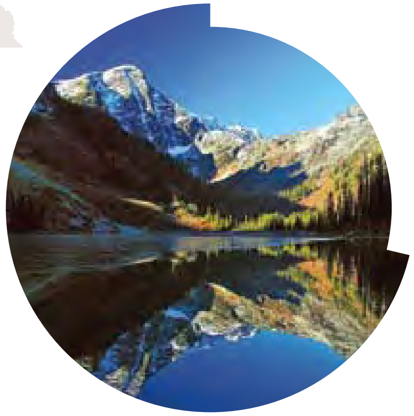
Government will work with First Nations communities to identify opportunities to benefit from oil and gas development. By developing a greater ability to participate in and benefit from oil and gas development, First Nations can play a much more active role in the industry. **The BC Energy Plan** also supports increasing First Nations role in the development of cross-cultural training initiatives for agencies and industry.

Conclusion

The BC Energy Plan: A Vision for Clean Energy Leadership sets the standard for proactively addressing the opportunities and challenges that lie ahead in meeting the energy needs for all the citizens of the province, now and in the future. Appendix A provides a detailed listing of the policy actions of the plan.

The BC Energy Plan will attract new investments, help develop and commercialize new technology, build partnerships with First Nations, and ensures a strong environmental focus.

British Columbia has a proud history of innovation that has resulted in 90 per cent of our power generation coming from clean sources. This plan builds on that foundation and ensures B.C. will be at the forefront of environmental and economic leadership for years to come.



APPENDIX A The BC Energy Plan: Summary of Policy Actions

ENERGY CONSERVATION AND EFFICIENCY

1. Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.
2. Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.
3. Encourage utilities to pursue cost effective and competitive demand side management opportunities.
4. Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.
5. Implement Energy Efficiency Standards for Buildings by 2010.
6. Undertake a pilot project for energy performance labeling of homes and buildings in coordination with local and federal governments, First Nations, and industry associations.
7. New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
8. Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.
9. Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.

ELECTRICITY

10. Ensure self-sufficiency to meet electricity needs, including "insurance" by 2016.
11. Establish a standing offer for clean electricity projects up to 10 megawatts.
12. The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.
13. Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.
14. Ensure that the province remains consistent with North American transmission reliability standards.
15. Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.
16. Establish the existing heritage contract in perpetuity.
17. Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.
18. All new electricity generation projects will have zero net greenhouse gas emissions.
19. Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
20. Require zero greenhouse gas emissions from any coal thermal electricity facilities.
21. Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
22. Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.
23. No nuclear power.
24. Review BC Utilities Commissions' role in considering social and environmental costs and benefits.
25. Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.
26. Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.
27. Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.
28. Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.

ALTERNATIVE ENERGY

29. Establish the Innovative Clean Energy Fund to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.
30. Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.
31. Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.
32. Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.
33. Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.
34. Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.
35. Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.

OIL AND GAS

36. Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.
37. Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.
38. Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
39. Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.
40. Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.
41. Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.
42. Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.
43. Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.
44. Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.
45. Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.
46. Encourage the development of conventional and unconventional resources.
47. Support the growth of British Columbia's oil and gas service sector.
48. Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.
49. Encourage the development of new technologies.
50. Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.
51. Provide information about local oil and gas activities to local governments, education and health service providers to inform and support the development of necessary social infrastructure.
52. Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.
53. Support First Nations in providing cross-cultural training to agencies and industry.
54. Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.
55. Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.

Energy in Action

POWERSMART
BC Hydro offers a variety of incentives to adopt energy saving technologies. Incentives such as rebates on efficient lighting or windows encourages British Columbians to improve the energy efficiency of their homes and businesses.

PROVINCIAL SALES TAX EXEMPTIONS
Tax breaks are offered for a wide variety of energy efficient items, making it easier to conserve energy. Tax concessions are in place for alternative fuel and hybrid vehicles as well as some alternative fuels. Bicycles and some bicycle parts are exempt from provincial sales tax, as are a variety of materials, such as Energy Star® qualified windows, that can make homes more energy efficient.

NET METERING
The Net Metering program offered by BC Hydro for customers with small generating facilities, allows customers to lower their environmental impact and take responsibility for their own power production. The customer is only billed for their "net consumption"; the total amount of electricity used minus the total produced. Net Metering helps to move the province towards electricity self sufficiency and expands clean electricity generation.

POWERING THE ECONOMY
The Oil and Gas sector invested $4.6 billion in B.C. in 2005 and contributed more to the provincial treasury than any other resource in 2005/06. In 2006 1,416 oil and gas wells were drilled in the province and between 2002 and 2005, summer drilling increased 242 per cent.

FRIDGE BUY-BACK PROGRAM
This program offers customers $30 in cash and no-cost pickup and disposal of an old, inefficient second fridge. If all second operating fridges in B.C. were recycled, we would save enough energy to power all the homes in the city of Chilliwack for an entire year.

LIGHTING REBATES
This program offers instant rebate coupons for the retail purchase of Energy Star® light fixtures and Energy Star® CFLs (Compact Fluorescent Lights).

WINDOWS REBATE
The Windows Rebate Program offers rebates for the installation of Energy Star® windows in new, renovated or upgraded single-family homes, duplexes, townhouses or apartments.

PRODUCT INCENTIVE PROGRAM
The Product Incentive Program provides financial incentives to organizations which replace inefficient products with energy efficient technologies or add on products to existing systems to make them more efficient.

HIGH-PERFORMANCE BUILDING PROGRAM FOR LARGE COMMERCIAL BUILDINGS
Financial incentives, resources, and technical assistance are available to help qualified projects identify energy saving strategies early in the design process; evaluate alternative design options and make a business case for the high-performance design; and, offset the incremental costs, if any, of the energy-efficient measures in the high-performance design.

HIGH-PERFORMANCE BUILDING PROGRAM FOR SMALL TO MEDIUM COMMERCIAL BUILDINGS
Incentives and tools are offered to help owners and their design teams create and install more effective and energy-efficient lighting in new commercial development projects.

NEW HOME PROGRAM
Builders and developers are encouraged to build energy efficient homes by offering financial incentives and Power Smart branding for homes that achieve energy efficient ratings.

ANALYZE MY HOME
BC Hydro offers an online tool that provides a free, personalized breakdown of a customer's home energy use and recommendations on where improvements can be made to lower consumption.

CONSERVATION RESEARCH INITIATIVE
A 12-month study in six communities that examines how adjusting the price of electricity at different times of day influences energy use by residential customers, and how individual British Columbians can make a difference in conserving power in their homes and help meet the growing demand for electricity in B.C.

THE GREEN BUILDINGS PROGRAM
Provides tools and resources to support school districts, universities, colleges, and health authorities to improve the energy efficiency of their buildings across the province.

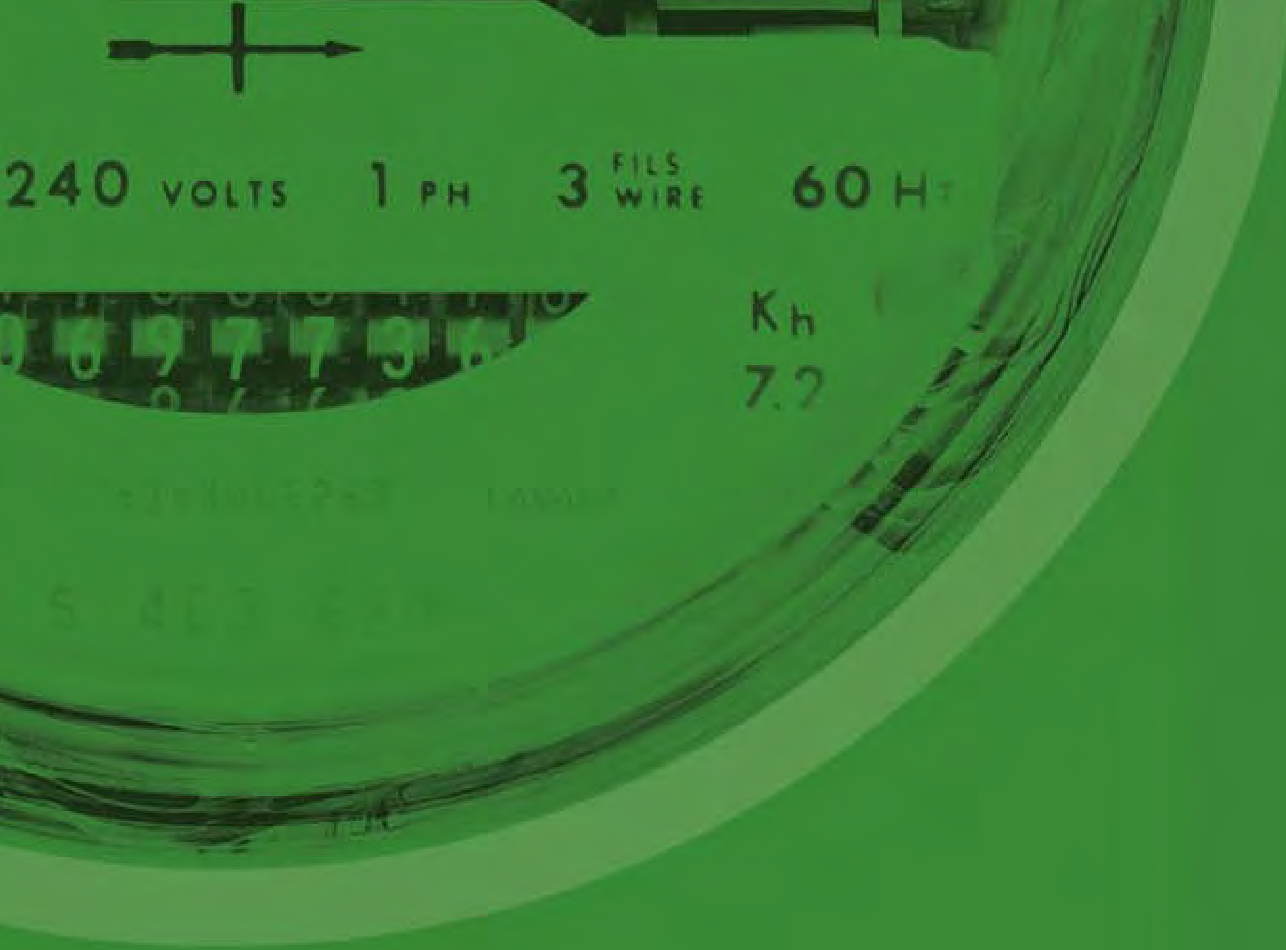
ATTRACTING WORKERS
The Ministry of Energy, Mines and Petroleum Resources hosts job fairs across B.C. to attract workers to the highly lucrative oil and gas sector. Job fairs were held in 14 communities in 2005 and 16 communities in 2006 attracting thousands of people and resulting in hundreds of job offers. Centre of Excellence Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

CENTRE OF EXCELLENCE
Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

100,000 SOLAR ROOFS FOR B.C.
The Ministers of Environment, and Energy, Mines and Petroleum Resources are sponsoring the development of a plan that will see the aggressive adoption of solar technology in B.C. The goal of the project is to see the installation of solar roofs and walls for hot water heating and photovoltaic electricity generation on 100,000 buildings around B.C.

PARTNERING FOR SUCCESS
Since 2003, the Province of B.C. has partnered in the construction of $158 million in new oil and gas road and pipeline infrastructure. The Sierra Yoyo Desan Road public private partnership improved the road allowing year round drilling activity in the Greater Sierra natural gas play. The project was recognized with the Gold Award for Innovation and Excellence from the Canadian Council for Public Private Partnerships in 2004.

ENERGY EFFICIENT BUILDINGS: A PLAN FOR BC
This strategy will lower energy costs for new and existing buildings by $127 million in 2010 and $474 million in 2020, and reduce greenhouse gas emissions by 2.3 million tonnes in 2020. The Province is implementing ten policy and market measures in partnership with the building industry, energy consumer groups, utilities, non-governmental organizations, and the federal government.



For more information on
The BC Energy Plan:
A Vision for Clean Energy Leadership, contact:

Ministry of Energy, Mines and Petroleum Resources
1810 Blanshard Street
PO Box 9318 Stn Prov Govt
Victoria, BC V8W 9N3

250.952.0241

www.energyplan.gov.bc.ca

BRITISH COLUMBIA
The Best Place on Earth

Ministry of
Energy, Mines and
Petroleum Resources

Certified correct as passed Third Reading on the 8th day of April, 2008

Ian D. Izard, Q.C., Law Clerk

MINISTER OF ENERGY, MINES AND PETROLEUM RESOURCES

BILL 15 – 2008

UTILITIES COMMISSION AMENDMENT ACT, 2008

HER MAJESTY, by and with the advice and consent of the Legislative Assembly of the Province of British Columbia, enacts as follows:

1 ***Section 1 of the Utilities Commission Act, R.S.B.C. 1996, c. 473, is amended by adding the following definitions:***

"demand-side measure" means a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand;

"government's energy objectives" means the following objectives of the government:

(a) to encourage public utilities to reduce greenhouse gas emissions;

(b) to encourage public utilities to take demand-side measures;

(c) to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources;

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;

(e) to encourage public utilities to use innovative energy technologies

(i) that facilitate electricity self-sufficiency or the fulfillment of their long-term transmission requirements, or

(ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy;

(f) to encourage public utilities to take prescribed actions in support of any other goals prescribed by regulation;

"transmission corporation" has the same meaning as in the *Transmission Corporation Act*;.

2 ***Section 2 (4) is amended by striking out*** "1 to 3 and 5 to 13" ***and substituting*** "1 to 13".

3 ***Section 3 is repealed and the following substituted:***

Commission subject to direction

3 (1) Subject to subsection (3), the Lieutenant Governor in Council, by regulation, may issue a direction to the commission with respect to the exercise of the powers and the performance of the duties of the commission, including, without limitation, a direction requiring the commission to exercise a power or perform a duty, or to refrain from doing either, as specified in the regulation.

(2) The commission must comply with a direction issued under subsection (1), despite

(a) any other provision of

(i) this Act, except subsection (3) of this section, or

(ii) the regulations, or

(b) any previous decision of the commission.

(3) The Lieutenant Governor in Council may not under subsection (1) specifically and expressly

(a) declare an order or decision of the commission to be of no force or effect, or

(b) require the commission to rescind an order or a decision.

4 ***Section 5 is amended***

(a) by adding the following subsection:

(0.1) In this section, **"minister"** means the minister responsible for the administration of the *Hydro and Power Authority Act.*,

(b) in subsection (3) by adding "British Columbia or" ***after*** "enactment of", ***and***

(c) by adding the following subsections:

(4) The commission, in accordance with subsection (5), must conduct an inquiry to make determinations with respect to British Columbia's infrastructure and capacity needs for electricity transmission for the period ending 20 years after the day the inquiry begins or, if the terms of reference given under subsection (6) specify a different period, for that period.

(5) An inquiry under subsection (4) must begin

(a) by March 31, 2009, and

(b) at least once every 6 years after the conclusion of the previous inquiry,

unless otherwise ordered by the Lieutenant Governor in Council.

(6) For an inquiry under subsection (4), the minister may specify, by order, terms of reference requiring and empowering the commission to inquire into the matter referred to in that subsection, including terms of reference regarding the manner

in which and the time by which the commission must issue its determinations under subsection (4).

(7) The minister may declare, by regulation, that the commission may not, during the period specified in the regulation, reconsider, vary or rescind a determination made under subsection (4).

(8) Despite section 75, if a regulation is made for the purposes of subsection (7) of this section with respect to a determination, the commission is bound by that determination in any hearing or proceeding held during the period specified in the regulation.

(9) The commission may order a public utility to submit an application under section 46, by the time specified in the order, in relation to a determination made under subsection (4).

5 Section 22 is repealed and the following substituted

Exemptions

22 (1) In this section:

"eligible person" means a person, or a class of persons, that

(a) generates, produces, transmits, distributes or sells electricity,

(b) for the purpose of heating or cooling any building, structure or equipment or for any industrial purpose, heats, cools or refrigerates water, air or any heating medium or coolant, using for that purpose equipment powered by a fuel, a geothermal resource or solar energy, or

(c) enters into an energy supply contract, within the meaning of section 68, for the provision of electricity;

"minister" means the minister responsible for the administration of the *Hydro and Power Authority Act*.

(2) The minister, by regulation, may

(a) exempt from any or all of section 71 and the provisions of this Part

(i) an eligible person, or

(ii) an eligible person in respect of any equipment, facility, plant, project, activity, contract, service or system of the eligible person, and

(b) in respect of an exemption made under paragraph (a), impose any terms and conditions the minister considers to be in the public interest.

(3) The minister, before making a regulation under subsection (2), may refer the matter to the commission for a review.

6 Section 43 (1) is repealed and the following substituted:

(1) A public utility must, for the purposes of this Act,

(a) answer specifically all questions of the commission, and

(b) provide to the commission

(i) the information the commission requires, and

(ii) a report, submitted annually and in the manner the commission requires, regarding the demand-side measures taken by the public utility during the period addressed by the report, and the effectiveness of those measures.

(1.1) The authority, in addition to providing the information and reports referred to in subsection (1), must provide to the commission, in accordance with the regulations, an annual report comparing the electricity rates charged by the authority with electricity rates charged by public utilities in other jurisdictions in North America, including an assessment of whether the authority's electricity rates are competitive with those other rates.

7 *The following sections are added:*

Long-term resource and conservation planning

44.1 (1) In this section, **"demand increase"** means the greater of

(a) the difference between

(i) the sum of the estimate referred to in subsection (4) (b) and a prescribed amount, if any, and

(ii) the demand the authority would serve during the period referred to in subsection (4) (b) if the demand in each year of that period remains equal to the demand referred to in subsection (4) (a), and

(b) zero.

(2) Subject to subsection (4), a public utility must file with the commission, in the form and at the times the commission requires, a long-term resource plan including all of the following:

(a) an estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan;

(b) a plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;

(c) an estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;

(d) a description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);

(e) information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c);

(f) an explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures;

(g) any other information required by the commission.

(3) The commission may exempt a public utility from the requirement to include in a long-term resource plan filed under subsection (2) any of the information referred to in paragraphs (a) to (f) of that subsection if the commission is satisfied that the information is not applicable with respect to the nature of the service provided by the public utility.

(4) A long-term resource plan filed under subsection (2) by the authority before the end of the 2020 calendar year must include, in addition to everything referred to in subsection (2) (a) to (g), all of the following:

(a) a statement of the demand for electricity the authority served in the year beginning on April 1, 2007, and ending on March 31, 2008;

(b) an estimate of the total demand for electricity the authority would expect to serve in the period beginning on April 1, 2008, and ending on March 31, 2021, if no new demand-side measures are taken during that period;

(c) a statement of the demand-side measures the authority would need to take so that, in combination with demand-side measures taken by the government of British Columbia or of Canada or a local authority, the demand increase would be reduced by 50% by 2020.

(5) The commission may establish a process to review long-term resource plans filed under subsection (2).

(6) After reviewing a long-term resource plan filed under subsection (2), the commission must

(a) accept the plan, if the commission determines that carrying out the plan would be in the public interest, or

(b) reject the plan.

(7) The commission may accept or reject, under subsection (6), a part of a public utility's plan, and, if the commission rejects a part of a plan,

(a) the public utility may resubmit the part within a time specified by the commission, and

(b) the commission may accept or reject, under subsection (6), the part resubmitted under paragraph (a) of this subsection.

(8) In determining under subsection (6) whether to accept a long-term resource plan, the commission must consider

(a) the government's energy objectives,

(b) whether the plan is consistent with the requirements under sections 64.01 and 64.02, if applicable,

(c) whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures, and

(d) the interests of persons in British Columbia who receive or may receive service from the public utility.

(9) In accepting under subsection (6) a long-term resource plan, or part of a plan, the commission may do one or both of the following:

(a) order that a proposed utility plant or system, or extension of either, referred to in the accepted plan or the part is exempt from the operation of section 45 (1);

(b) order that, despite section 75, a matter the commission considers to be adequately addressed in the accepted plan or the part is to be considered as conclusively determined for the purposes of any hearing or proceeding to be conducted by the commission under this Act, other than a hearing or proceeding for the purposes of section 99.

Expenditure schedule

44.2 (1) A public utility may file with the commission an expenditure schedule containing one or more of the following:

(a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;

(b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;

(c) a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.

(2) The commission may not consent under section 61 (2) to an amendment to or a rescission of a schedule filed under section 61 (1) to the extent that the amendment or the rescission is for the purpose of recovering expenditures referred to in subsection (1) (a) of this section, unless

(a) the expenditure is the subject of a schedule filed and accepted under this section, or

(b) the amendment or rescission is for the purpose of setting an interim rate.

(3) After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5) and (6), must

(a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or

(b) reject the schedule.

(4) The commission may accept or reject, under subsection (3), a part of a schedule.

(5) In considering whether to accept an expenditure schedule, the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

(c) whether the schedule is consistent with the requirements under section 64.01 or 64.02, if applicable,

(d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and

(e) the interests of persons in British Columbia who receive or may receive service from the public utility.

(6) If the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1 (6),

(a) subsection (5) of this section does not apply with respect to that expenditure, and

(b) the commission must accept under subsection (3) the expenditure in the expenditure schedule.

8 *Section 45 (6.1) and (6.2) is repealed.*

9 *Section 46 is amended*

(a) in subsection (3) by striking out "The commission" *and substituting* "Subject to subsections (3.1) and (3.2), the commission", *and*

(b) by adding the following subsections:

(3.1) In deciding whether to issue a certificate under subsection (3), the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any, and

(c) whether the application for the certificate is consistent with the requirements imposed on the public utility under sections 64.01 and 64.02, if applicable.

(3.2) Section (3.1) does not apply if the commission considers that the matters addressed in the application for the certificate were determined to be in the public interest in the course of considering a long-term resource plan under section 44.1.

10 Section 58 is amended by adding the following subsections:

(2.1) The commission must set rates for the authority in accordance with

(a) the prescribed requirements, if any, and

(b) the prescribed factors and guidelines, if any.

(2.2) A requirement prescribed for the purposes of subsection (2.1) (a) applies despite

(a) any other provision of

(i) this Act, including, for greater certainty, section 58.1, or

(ii) the regulations, except a regulation under section 3, or

(b) any previous decision of the commission.

(2.3) Subsections (2.1) (a) and (2.2) are repealed on March 31, 2010.

(2.4) Despite subsection (2.3), a requirement prescribed for the purposes of subsection (2.1) (a) that is in effect immediately before March 31, 2010, continues to apply after that date as though subsection (2.2) were still in force, unless the prescribed requirement is amended or repealed after that date.

11 The following section is added:

Rate rebalancing

58.1 (1) In this section, **"revenue-cost ratio"** means the amount determined by dividing the authority's revenues from a class of customers during a period of time by the authority's costs to serve that class of customers during the same period of time.

(2) This section applies despite

(a) any other provision of

(i) this Act, or

(ii) the regulations, except a regulation under section 3 or 125.1 (4) (f), or

(b) any previous decision of the commission.

(3) The following decision and orders of the commission are of no force or effect to the extent that they require the authority to do anything for the purpose of changing revenue-cost ratios:

(a) 2007 RDA Phase 1 Decision, issued October 26, 2007;

(b) order G-111-07, issued September 7, 2007;

(c) order G-130-07, issued October 26, 2007;

(d) order G-10-08, issued January 21, 2008,

and the rates of the authority that applied immediately before this section comes into force continue to apply and are deemed to be just, reasonable and not unduly discriminatory.

(4) Nothing in subsection (3) prevents the commission from setting rates for the authority, but the commission may not set rates for the authority for the purpose of changing the revenue-cost ratio for a class of customers.

(5) Subsection (4) is repealed on March 31, 2010.

(6) Nothing in subsection (3) prevents the commission from setting rates for the authority, but the commission, after March 31, 2010, may not set rates for the authority such that the revenue-cost ratio, expressed as a percentage, for any class of customers increases by more than 2 percentage points per year compared to the revenue-cost ratio for that class immediately before the increase.

12 ***Section 61 (2) is amended by adding*** "rescinded or" ***after*** "must not be".

13 ***The following Part is added:***

PART 3.1 – ENERGY SECURITY AND THE ENVIRONMENT

Electricity self-sufficiency

64.01 (1) The authority must

(a) by the 2016 calendar year, achieve electricity self-sufficiency according to the prescribed criteria, and

(b) maintain, according to the prescribed criteria, electricity self-sufficiency in each calendar year after achieving it.

(2) A public utility, in planning for

(a) the construction or extension of generation facilities, and

(b) energy purchases,

must consider the government's goal that British Columbia be electricity self-sufficient by the 2016 calendar year and maintain self-sufficiency after that year.

Clean and renewable resources

64.02 (1) To facilitate the achievement of the government's goal that at least 90% of the electricity generated in British Columbia be generated from clean or renewable resources, a person to whom this section applies

(a) must pursue actions to meet the prescribed targets in relation to clean or renewable resources, and

(b) must use the prescribed guidelines in planning for

(i) the construction or extension of generation facilities, and

(ii) energy purchases.

(2) This section applies to

(a) the authority, and

(b) a prescribed public utility, if any, and a public utility in a class of prescribed public utilities, if any.

Standing offer

64.03 (1) In this section, **"eligible facility"** means a generation facility that

(a) either

(i) has only one generator with a nameplate capacity of 10 megawatts or less or has more than one generator and the total nameplate capacity of all of them is 10 megawatts or less, or

(ii) meets the prescribed requirements, and

(b) either

(i) is a high-efficiency cogeneration facility, or

(ii) generates energy by means of a prescribed technology or from clean or renewable resources,

but does not include a prescribed generation facility or class of generation facilities.

(2) The authority must establish and maintain a standing offer

(a) during the times prescribed by and in accordance with the regulations, if any, and

(b) on the terms and conditions, if any, approved by the commission under subsection (3),

to enter into an energy supply contract for the purchase of electricity from eligible facilities.

(3) Subject to regulations made for the purposes of subsection (2) (a), the commission, by order and on application by the authority, may approve terms and conditions for the purposes of subsection (2) (b) if the commission considers that the terms and conditions are in the public interest.

(4) The commission may not issue an order under section 71 (3) with respect to a contract entered into in accordance with the regulations made for the purposes of subsection (2) (a), and exclusively on the terms and conditions referred to in subsection (2) (b), of this section.

Smart meters

64.04 (1) In this section:

"private dwelling" means

(a) a structure that is occupied as a private residence, or

(b) if only part of a structure is occupied as a private residence, that part of the structure;

"smart meter" means a meter that meets the prescribed requirements, and includes related components, equipment and metering and communication infrastructure that meet the prescribed requirements.

(2) Subject to subsection (3), the authority must install and put into operation smart meters in accordance with and to the extent required by the regulations.

(3) The authority must complete all obligations imposed under subsection (2) by the end of the 2012 calendar year.

(4) If a public utility, other than the authority, makes an application under the Act in relation to advanced meters, the commission, in considering that application, must consider the government's goal of having advanced meters and associated infrastructure in use with respect to customers other than those of the authority.

(5) The authority may, by itself, or by its engineers, surveyors, agents, contractors, subcontractors or employees, enter on any land, other than a private dwelling, without the consent of the owner, for a purpose relating to the use, maintenance, safeguarding, installation, replacement, repair, inspection, calibration or reading of its meters, including smart meters.

14 ***Section 71 (2) is repealed and the following substituted:***

(2) The commission may make an order under subsection (3) if the commission, after a hearing, determines that an energy supply contract to which subsection (1) applies is not in the public interest.

(2.1) In determining under subsection (2) whether an energy supply contract is in the public interest, the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

(c) whether the energy supply contract is consistent with requirements imposed under section 64.01 or 64.02, if applicable,

(d) the interests of persons in British Columbia who receive or may receive service from the public utility,

(e) the quantity of the energy to be supplied under the contract,

(f) the availability of supplies of the energy referred to in paragraph (e),

(g) the price and availability of any other form of energy that could be used instead of the energy referred to in paragraph (e), and

(h) in the case only of an energy supply contract that is entered into by a public utility, the price of the energy referred to in paragraph (e).

(2.2) Subsection (2.1) (a) to (c) does not apply if the commission considers that the matters addressed in the energy supply contract filed under subsection (1) were determined to be in the public interest in the course of considering a long-term resource plan under section 44.1.

(2.3) A public utility may submit to the commission a proposed energy supply contract setting out the terms and conditions of the contract and a process the public utility intends to use to acquire power from other persons in accordance with those terms and conditions.

(2.4) If satisfied that it is in the public interest to do so, the commission, by order, may approve a proposed contract submitted under subsection (2.3) and a process referred to in that subsection.

(2.5) In considering the public interest under subsection (2.4), the commission must consider

(a) the government's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1,

(c) whether the application for the proposed contract is consistent with the requirements imposed on the public utility under sections 64.01 and 64.02, if applicable, and

(d) the interests of persons in British Columbia who receive or may receive service from the public utility.

(2.6) If the commission issues an order under subsection (2.4), the commission may not issue an order under subsection (3) with respect to a contract

(a) entered into exclusively on the terms and conditions, and

(b) as a result of the process

referred to in subsection (2.3).

15 ***Section 88 (4) is amended by striking out*** "a matter that is subject" ***and substituting*** "a person, or a person in respect of a matter, who has been exempted under".

16 ***Section 108 (b) is amended by adding*** "responsible for the administration of the *Hydro and Power Authority Act*" ***after*** "minister".

17 ***The following sections are added:***

Minister's regulations

125.1 (1) In this section, **"minister"** means the minister responsible for the administration of the *Hydro and Power Authority Act*.

(2) The minister may make regulations respecting the government's energy objectives, as defined in section 1, including, without limitation, regulations as follows:

(a) defining a word or phrase used in the definition;

(b) prescribing actions and goals for the purposes of paragraph (f) of the definition;

(c) establishing factors or guidelines the commission must use in considering the government's energy objectives, including guidelines regarding the relative priority of the objectives referred to in paragraphs (a) to (f) of the definition.

(3) A regulation under subsection (2) may be made with respect to the government's energy objectives generally or with respect to their application in any particular case.

(4) The minister may make regulations as follows:

(a) making declarations for the purposes of section 5 (7);

(b) respecting exemptions under section 22;

(c) respecting reports to be provided to the commission by the authority under section 43 (1.1), including, without limitation, respecting the jurisdictions with which comparisons are to be made, the rate classes to be considered, the factors to be used in making the comparisons and conducting the assessments, and the meaning to be given to the word "competitive";

(d) prescribing, for the purposes of paragraph (a) (i) of the definition of "demand increase" in section 44.1 (1), an amount representing an increase in resource requirements of the authority not related to an estimated increased demand referred to in section 44.1 (4) (b);

(e) for the purposes of section 44.1 and 44.2,

(i) prescribing rules for determining whether a demand-side measure, or a class of demand-side measures, is adequate, cost-effective or both,

(ii) declaring a demand-side measure, or a class of demand-side measures, to be cost effective and necessary for adequacy,

(iii) prescribing rules or factors a public utility must use in making the estimate referred to in section 44.1 (2) (a), and

(iv) prescribing rules or factors the authority must use in making the estimate referred to in section 44.1 (4) (b);

(f) prescribing requirements for the purposes of section 58 (2.1) (a);

(g) prescribing factors and guidelines for the purposes of section 58 (2.1) (b), including, without limitation, factors and guidelines to encourage

(i) energy conservation or efficiency,

(ii) the use of energy during periods of lower demand,

(iii) the development and use of energy from clean or renewable resources, or

(iv) the reduction of the energy demand a public utility must serve;

(h) defining a term or phrase used in section 58.1 and not defined in this Act;

(i) identifying facts that must be used in interpreting the definition in section 58.1;

(j) defining a term or phrase used in Part 3.1 and not defined in that Part;

(k) prescribing criteria respecting self-sufficiency for the purposes of section 64.01 (1) (a) and (b);

(l) prescribing targets for the purposes of section 64.02 (1) (a), guidelines for the purposes of section 64.02 (1) (b) and public utilities and classes of public utilities for the purposes of section 64.02 (2) (b);

(m) for the purposes of section 64.03, respecting eligible facilities, including prescribing generation facilities and classes of generation facilities, and respecting the standing offer to be established and maintained under that section;

(n) for the purposes of section 64.04, respecting smart meters and their installation, including, without limitation,

(i) the types of smart meters to be installed, including the features or functions each meter must have or be able to perform, and

(ii) the classes of users for whom smart meters must be installed, and requiring the authority to install different types of smart meters for different classes of users;

(o) prescribing standard-making bodies for the purposes of section 125.2 (1) and matters for the purposes of section 125.2 (3) (d);

(p) prescribing owners, operators, direct users, generators and distributors, or classes of any of them, for the purposes of section 125.2 (8).

(5) In making a regulation under this section, the minister may

(a) make regulations of specific or general application, and

(b) make different regulations for different persons, places, things, measures, transactions or activities.

Adoption of reliability standards, rules or codes

125.2 (1) In this section:

"reliability standard" means a reliability standard, rule or code established by a standard-making body for the purpose of being a mandatory reliability standard for planning and operating the North American bulk power system, and includes any substantial change to any of those standards, rules or codes;

"standard-making body" means

(a) the North American Electric Reliability Corporation,

(b) the Western Electricity Coordinating Council, and

(c) a prescribed standard-making body.

(2) For greater certainty, the commission has exclusive jurisdiction to determine whether a reliability standard is in the public interest and should be adopted in British Columbia.

(3) The transmission corporation must review each reliability standard and provide to the commission, in accordance with the regulations, a report assessing

(a) any adverse impact of the reliability standard on the reliability of electricity transmission in British Columbia if the reliability standard were adopted under subsection (6),

(b) the suitability of the reliability standard for British Columbia,

(c) the potential cost of the reliability standard if it were adopted under subsection (6), and

(d) any other matter prescribed by regulation or identified by order of the commission for the purposes of this section.

(4) The commission may make an order for the purposes of subsection (3) (d).

(5) If the commission receives a report under subsection (3), the commission must

(a) make the report available to the public in a reasonable manner, which may include by electronic means, and for a reasonable period of time, and

(b) consider any comments the commission receives in reply to the publication referred to in paragraph (a).

(6) After complying with subsection (5), the commission, subject to subsection (7), must adopt the reliability standards addressed in the report if the commission considers that the reliability standards are required to maintain or achieve consistency in British Columbia with other jurisdictions that have adopted the reliability standards.

(7) The commission is not required to adopt a reliability standard under subsection (6) if the commission determines, after a hearing, that the reliability standard is not in the public interest.

(8) A reliability standard adopted under subsection (6) applies to every

(a) prescribed owner, operator and direct user of the bulk power system, and

(b) prescribed generator and distributor of electricity.

(9) Subsection (8) applies to a person prescribed for the purposes of that subsection despite any exemption issued to the person under section 22 or 88 (3).

(10) The commission may make orders providing for the administration of adopted reliability standards.

(11) The commission, on its own motion or on complaint, may

(a) rescind an adoption made under subsection (6), or

(b) adopt a reliability standard previously rejected under subsection (7) if the commission determines, after a hearing, that the rescission or adoption is in the public interest.

(12) The commission, without the approval of the minister responsible for the administration of the *Hydro and Power Authority Act*, may not set a standard or rule under section 26 of this Act with respect to a matter addressed by a reliability standard assessed in a report submitted to the commission under subsection (3) of this section.

Consequential Amendments and Transition

Insurance Corporation Act

18 ***Section 44 of the Insurance Corporation Act, R.S.B.C. 1996, c. 228, is amended by striking out*** "other than sections 22, 23 (1) (a) to (d) and (2), 25 to 38, 40, 41, 45 to 57, 59 (2) and (3), 60 (1) (b) (ii) and (2) to (4), 97, 98, 106 (1) (k), 107 to 109 and 114 and Parts 4 and 5 of that Act," ***and substituting*** "other than sections 3, 5 (4) to (9), 22, 23 (1) (a) to (d) and (2), 25 to 38, 40, 41, 43 (1) (b) (ii), 44.1, 44.2, 45 to 57, 59 (2) and (3), 60 (1) (b) (ii) and (2) to (4), Part 3.1, 97, 98, 106 (1) (k), 107 to 109 and 114, Parts 4 and 5 and sections 125.1 and 125.2 of that Act,".

Water Utility Act

19 ***Section 4 (b) of the Water Utility Act, R.S.B.C. 1996, c. 485, is amended by striking out*** "other than sections 28, 29 and 45 (2), (3), (5) and (6)," ***and substituting*** "other than sections 28, 29, 44.1, 44.2, 45 (2), (3), (5) and (6), 58 (2.1) and (2.2) and 58.1, Part 3.1 and sections 125.1 and 125.2,".

Transition

20 (1) For greater certainty, a regulation made under section 3 of the *Utilities Commission Act*, as that section read immediately before the date section 3 of this Act comes into force, if that regulation was in effect immediately before that date, remains in effect and is deemed to be a regulation under section 3 of the *Utilities Commission Act* as that section reads immediately after section 3 of this Act comes into force.

(2) An exemption under section 22 of the *Utilities Commission Act*, as that section read immediately before the date section 5 of this Act comes into force, if that exemption was in effect immediately before that date, remains in effect and is deemed to be an exemption under section 22 of the *Utilities Commission Act* as that section reads immediately after section 5 of this Act comes into force.

Commencement

21 The provisions of this Act referred to in column 1 of the following table come into force as set out in column 2 of the table:

Item	Column 1 **Provisions of Act**	Column 2 **Commencement**
1	Anything not elsewhere covered by this table	The date of Royal Assent
2	Section 11	March 31, 2008

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Victoria, 2008

In this IR #3 referrals are made to FortisBC IR#2 response, source : B-3
Submitted: 19/03/2008

I Please accept herewith a reminder about outstanding info requests in my IR # 1 and IR # 2. Based on the responses I ask to grant leave that additional IR can be submitted by me based on those outstanding responses by FortisBC.

A FortisBC has responded to all of the questions in IR # 1 and # 2. Where required by the Amendments to the Original Application, updated responses were provided on March 28, 2008.

II In the following please accept my Info Request # 3

Q1 Please state whether a technology vendor has been chosen.

A1 No vendor has been chosen.

Q1a If not, please state when FortisBC most likely will have chosen a vendor.

A1a Vendor selection will occur after approval of the Amended Application and subsequent to a formal Request for Proposal process.

Q1b If yes, please provide the relevant specifications already asked in my earlier IRs.

A1b No vendor has been chosen.

Q2 please provide a cost comparison of a wireless metering system and a non-wireless metering system that transmits data via shared

a. old conventional telephone line

b. telephone fiber-optic line

c. Internet/TV cable line

Q2 FortisBC is not aware of any AMI systems that use telephone lines, fiber-optic lines or conventional Internet connections for the metering endpoint network (LAN), and is therefore unable to provide a cost estimate.

Q3 reference IR#2 Q3a FortisBC A3a Table A3a

Please provide Table A3a with power density in units with microwatt/cm square

A3 Please see Table A3a below displaying power density in units of microwatt/cm$^{2.}$

Table A3a: Maximum power density in units of uW/square centimeter

Equipment	Frequency (Mhz)	Distance (m)							
			0.25m	0.5m	1m	2m	5m	10m	20m
Spread Spectrum	902-928 2400-2483.5 5725-5875	uW/cm^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		0.0955	0.0239	0.00597	0.00149	0.000239	0.0000597	0.0000149
CDMA	824-849		255	63.7	15.9	3.98	0.637	0.159	0.0398

Q4 reference IR#2 Q3d

Please state whether FortisBC has to obtain a license from Industry Canada for using frequencies and please state the expected cost for the license and for using all the frequencies for the AMI.

A4 The requirement for an Industry Canada license depends first on whether the selected AMI technology uses radio frequency for the metering endpoint network. If the selected technology does use radio frequency and the frequency is licensed, then an Industry Canada license would be required. If the selected AMI technology does not use radio frequency, or the frequency used is not licensed, no license would be required. Devices not intended for communication in the licensed frequency bands are still regulated by Industry Canada with respect to maximum power emission.

License costs, if required, are estimated to cost approximately $5,000 annually.

Q5 reference IR#2 Q4 A4:

FortisBC is not aware about a vendor currently offering infrared technology for a similar project like AMI. Please state however, whether the use of infra-red technology would be possible for subject project , if not, please state why not.

A5 Infrared technology is not likely to be effective for use as a metering endpoint network since it is essentially a line-of-sight network. In other words, if anything visually interrupted the sight line between the meter and the collector, such as fog, rain, vegetation, vehicles or buildings, the communication link would fail.

Q6 reference IR#2 Q10 A10:

Please provide the info accurately about the chosen metering system's signal transmitting: Please state how often each day/week etc will the

reader transmit, see reference above.

A6 The answer provided in Karow IR No. 2 Q10 is accurate – AMI systems transmit data using different schemes, which results in differences in the duration and frequency with which they transmit data. An AMI system has not yet been chosen for this project.

Q7 Please provide lifetime expectancy of the presently/conventional meters, it is believed there are 2 different kinds.

A7 The life expectancy of both types of conventional meters (electromechanical and digital) is approximately the same at about 25 years.

Q8 Please state, whether on customer demand a wire-less meter not to be installed for medical reasons, is it possible that the old/existing meters remain installed and that the customer does the reading and sends the reading to FortisBC office? If not, please state why not.

A8 Please see the response to Karow IR No. 2 Q7. Furthermore, it is not possible for the customer to retain a conventional meter and send in readings for several reasons:

- Conventional meters cannot economically be reprogrammed for different time-based rates;
- Conventional meters are not generally capable of storing hourly or daily reads, and even if they were it would be unreasonable to expect customers to collect and provide this information on a regular basis;
- Customers are not always available to read their meters at the correct times;
- Customer reads would have to be audited regularly, increasing costs; and
- Data provided by the customer would have to be manually entered into the billing system, increasing costs.

Q9 Reference see attached Dr. Michrowsky's paper

Electromagnetic fields:

Questions and answers about wireless technologies

Does FortisBC dispute biological effect findings in the following, as cited out of Dr. Michrowsky paper, if so, please state reason/argument.

BIOLOGICAL EFFECTS OF MICROWAVES BELOW U.S. & CANADA'S REGULATORY LIMIT

(*micro*W/cm^2)	**Reported Biological Effects**	**References**
0.0000000000001	Altered genetic structure in *E. Coli*	Belyaev 1996
0.0000000001	Threshold of human sensitivity	Kositsky 2001
0.000000001	Altered EEG in human subjects	Bise 1978
0.0000000027	Growth stimulation in *Vicius fabus*	Brauer 1950
0.00000001	Effects on immune system in mice	Bundyuk 1994
0.00000002	Stimulation of ovulation in chickens	Kondra 1970
0.000005	Effect on cell growth in yeast	Grundler 1992
0.00001	Conditioned "avoidance" reflex in rats	Kositsky 2001
0.000027	Premature aging of pine needles	Selga 1996
0.001	**100 Yards / metres from Cell Phone**	
0.002	Sleep disorders, abnormal blood pressure, nervousness, weakness, fatigue, limb and joint pain, digestive problems, fewer schoolchildren promoted	Altpeter 1995, 1997
0.0027	Growth inhibition in *Vicius fabus*	Brauer 1950
0.0027 to 0.065	Smaller tree growth rings	Balodis 1996
0.007	**50 Feet from a Cordless Phone**	
0.01	Human sensation	Kolbun 1987
0.016	**1 Mile (1.6Km) from a Cellular Tower**	
0.06	Altered EEG, disturbed carbohydrate metabolism, enlarged adrenals, altered adrenal hormone levels, structural changes in liver, spleen, testes, and brain in white rats and rabbits	Dumanskij 1974
0.06	Slowing of the heart, change in EEG in rabbits	Serkyuk, reported in McRee 1980
0.05	**10 Feet /3 meters from a Wireless Computer**	
0.1	Increase in melatonin in cows	Stark 1997
0.1 to 1.8	Decreased life span, impaired reproduction, structural and developmental abnormalities in duckweed plants	Magone 1996
0.13	Decreased cell growth (human epithelial amnion cells)	Kwee 1997

0.168	Irreversible sterility in mice	Magras 1997
0.2 to 8.0	Childhood leukemia near transmitters	Hocking 1996
0.3	Impaired motor function, reaction time, memory and attention of school children, and altered sex ratio of children (fewer boys)	Kolodynski 1996
0.6	Change in calcium ion efflux from brain tissue	Dutta 1986
0.6	Cardiac arrhythmias and sometimes cardiac arrest (frogs)	Frey 1968
0–4	Altered white blood cell activity in schoolchildren	Chiang 1989
1.0	Headache, dizziness, irritability, fatigue, weakness, insomnia, chest pain, difficulty breathing, indigestion (humans—occupational exposure)	Simonenko 1998
1.0	Stimulation of white cells in guinea pigs	Shandala 1978
2.5	Breakdown of blood-brain barrier (used a digital cell phone to radiate)	Salford 1997
5.0	Leukemia, skin melanoma and bladder cancer near TV and FM transmitter	Dolk 1997
2.0	(lower “Microwave hearing” - clicking, buzzing, chirping, hissing, or high-pitched threshold notetones known)	Frey 1963, 1969, 1971, 1973, 1988, Justeson 1979, Olsen 1980, Wieske 1963, Lin 1978
5.0	Biochemical and histological changes in liver, heart, kidney, and brain tissue	Belokrinitskiy l982
10.0	Damaged mitochondria, nucleus of cells in hippocampus of brain	Belokrinitskiy 1982a
10.0	Impaired memory and visual reaction time in people living near transmitters	Chiang 1989
10.0	Decreased size of litter, increased number of stillborns in mice	Il’Chevich (reported in McRee 1980)
10.0	Redistribution of metals in the lungs, brain, heart, liver, kidney, muscles, spleen, bones, skin, blood	Shutenko 1981
1,000.0	United States ***FCC Exposure Limit***, ***Safety Code 6*** Canada limit	

A9 FortisBC disputes the validity of the biological effect findings as cited from the paper by Dr. Michrowski "Electromagnetic Fields: Questions and Answers About Wireless Technologies" (http://pacenet.homestead.com) for several reasons. This list is scientifically unconvincing as evidence of biological effects because 1) it ignores varying quality and relevance of different types of research studies; 2) the list reflects an incorrect interpretation or summary of the results of some of the studies; 3) no evidence is provided that the findings have been replicated, and replication is critical to establish the validity of scientific theories such as the idea that RF exposures at low levels of wireless devices can cause adverse health/biological impacts; 4) biological effects, if valid, do not always translate to adverse impacts on human health, and 5) the research cited has already been considered in the comprehensive reviews conducted by scientific organizations, including Health Canada, to develop exposure limits to prevent adverse effects on human health. These items are explained briefly below, with emphasis on the last item number five.

Observations reported in a single study, as presented by Dr. Michrowski, and copied by Mr. Karow as a finding of a biological effect, overlook important aspects of scientific research. In considering scientific findings, it is essential to recognize that studies vary in the quality of the study design, in the implementation of the design, in the relevance of the biological methods used, and even in the validity of the authors' interpretation of the finding. Observations in scientific studies must be interpreted in context of these factors, and other related research regarding the observations. While Mr. Karow cites single studies of different effects from Dr. Michrowski's list, observations in scientific studies are not considered valid unless they can be replicated, preferably in another laboratory setting. Even if an observation of a biological effect were valid, an impact on human health must be established to determine its relevance for public health decisions.[1]

If the AMI technology proposed by FortisBC used radio frequency energy (RF) technology, it would be in the range used by wireless technologies that are currently in use. As expressed in FortisBC's response to Karow IR No. 2, Q14 (Exhibit B-3), "Policies relating to radiofrequency field exposure are the domain of Health Canada, not FortisBC. On issues relating to health and safety, FortisBC takes guidance from provincial, federal, and international agencies."

FortisBC understands that Health Canada and other organizations, including international health authorities, have reviewed the research related to biological findings and health in the RF frequency range. The studies on the list submitted by Mr. Karow were completed or published from 1950 through 2001, and therefore, have been available and considered in the scientific reviews. These comprehensive reviews of the scientific research have been conducted by groups of scientists who have expertise in the many disciplines involved in research on RF and health over the years[2] (e.g. ICNIRP, 1998, 2003; Health Canada, 1999; IEEE/ICES 2005; NRPB, 2004; SCENHIR, 2007).

As a result of these weight-of-evidence reviews, International Commission on Non-Ionizing Radiation Protection (ICNIRP), the National Radiological Protection Board (NRPB), the Institute of Electrical and Electronics Engineers (IEEE), and

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[1] Health Canada also notes that a biological effect is not the same as, or a direct indication of health effect. Health Canada and Industry Canada's FAQ on Radio Frequency Fields, Question # 10, explains as follows:

"A biological effect occurs when a change can be measured in a biological system after an introduction of some type of stimuli (e.g. RF energy). However, the observation of a biological effect, in and of itself, does not necessarily suggest the existence of a health effect. A biological effect only becomes a health hazard when it causes detectable impairment of health."

[2] Dr. Michrowski's specific area of biological expertise, if any, is not available from the paper or the web site.

Health Canada have proposed exposure limits. The NRPB, now the Radiation Protection Division of the Health Protection Agency (HPA) of the United Kingdom, endorses the limits proposed by ICNIRP. The HPA website includes a position statement on WiFi, which includes the following:

> On the basis of current scientific information, exposures from WiFi equipment satisfy international guidelines. There is no consistent evidence of health effects from RF exposures below guideline levels and no reason why schools and others should not use WiFi equipment.
> http://www.hpa.org.uk/web/HPAweb&HPAwebStandard/HPAweb_C/11957337792

The relevant exposure limits in Health Canada are expressed in Safety Code 6 (Health Canada, 1999*).* The Royal Society of Canada reviewed research conducted through 2003 (Krewski et al, 1999; 2001 CF; 2007). The World Health Organization (WHO) recommends the exposure limits proposed by ICNIRP (1998, 2003).

The anticipated RF levels from the proposed AMI technology are minimal, and lower than RF levels of mobile phones. FortisBC anticipates that AMI technology will not contribute sufficient RF energy to increase current background levels to anything close to the exposure limits expressed by Health Canada in Safety Code 6 or ICNIRP.

References:

Australian Radiation Protection Agency and Nuclear Safety Agency (ARPANSA 2003)

Health Canada and Industry Canada Frequently Asked Questions (FAQ) on Radio Frequency Fields. http://www.ic.gc.ca/epic/site/smt-gst.nsf/print-en/sf08792e.html

Health Canada Environmental Health Directorate. Limits of Human Exposure to Radiofrequency Electromagnetic Fields in the Frequency Range from 3 KHZ to 300 GHZ - Safety Code 6 1999 99-EHD-237

Institute of Electrical and Electronics Engineers (IEEE/ICES, 2005)

International Commission on Non-Ionizing Radiation Protection (ICNIRP). Guidelines for Limiting Exposure to Time-Varying Electric, Magnetic, and Electromagnetic Fields (up to 300 GHz). Health Phys. 74:494-522, 1998.

International Commission on Non-Ionizing Radiation Protection (ICNIRP). Exposure to static and low frequency electromagnetic fields, biological effects and health consequences (0-100 kHz) – review of the scientific evidence on dosimetry, biological effects, epidemiological observations, and health consequences concerning exposure to static and low frequency electromagnetic fields (0-100 kHz). Matthes R, McKinlay AF, Bernhardt JH, Vecchia P, Beyret B (eds.). International Commission on Non-Ionizing Radiation Protection, 2003.

National Radiological Protection Board (NRPB). Review of the Scientific Evidence for Limiting Exposure to Electromagnetic Fields (0-300 GHz) Volume 15 No.3, 2004

Krewski et al., Royal Society of Canada Expert Panel on RF Fields (1999; 2001; 2007)

Scientific Committee on Emerging and Newly Identified Health Risks (SCENIHR, 2007) Possible Effects of Electromagnetic Fields on Human Health.

Q10 reference: Table A3a (B-3 Submitted: 19/03/2008) which was requested in IR#3,Q3 the power density to be modified in units from W/square meter into microWatt/square centimeter:

For the modified table (see Q3) please provide the reduction of the meters data signals' electromagnetic radiation (EMR) penetrating first a 25 cm thick wall of different materials;

a. conventional wood-framed house with wood boards outside (no stucco wire mesh) and gyp-rock panels inside

b. wood framed wall with outside stucco (including stucco wire mesh), gyp rock panels inside

c. brick wall out side, gyp rock panels inside,

d. cement wall (without rebar, gyp rock panels inside

e. cement wall outside with pre-fabricated rebar mesh

A10 Excluding the effects of the distance, for the frequency range of 100 MHz to 2.4 Ghz, power density will be reduced by a factor of 80 to 190 for a 25 cm wall of concrete. For wood, this factor will be between 1.5 and 2.7. Adding any material such as rebar and gyp-rock panel will further reduce this power density.

Q11 Please provide detailed info how the meters EMR do impact conductive materials at the distance of 0.25m, 0.50m, 1m, 2m, 5m, 10m and 20m away from the transmitting meter. Define a typical house- hold metal object with given measurements i.e. lamp on a metal stand..

A11 It is a well accepted fact that any object produces electromagnetic radiation. For example, a concrete wall produces electromagnetic energy of 422 Watts/square meter, with 2.3 milliWatts/square meter (or 0.23 microwatts/square centimeter) of it in the radio frequency range. Any source of radiated energy in the radio frequency spectrum that has the same power as the AMI system, whether man-made or of natural origin, is going to have a vanishingly small effect on a household object such as a metal lamp. As an example, a 5 degree Celsius change in the house temperature would change the radiated power from the concrete by 31 Watts/square meter (with 40microWatts/square meter in the radio frequency range).

Q12 Please provide detailed info how the meter's EMR do impact the household-wiring. In addition please state, whether the house hold wiring is acting as a receiving antenna so that the meters EMR are received and do travel as induced secondary EMR all along the house wiring system.

A12 A house wiring system is a very poor antenna as its shape is not designed to pick up radio frequency signals. Considering that the meter radiates at an extremely low energy level, the effect of a meter's radio emission on household-wiring is negligible.

Q13 Please state the behavior of the secondary EMR in Q12, whether the secondary EMR will be amplified, thus the power density in the wiring system in a room's wall 20 m away from the meter could possibly be greater than at just plain 20 m air distance.

A13 Household wiring cannot amplify the energy it receives.

Q14 Please state whether secondary induced EMR in conductive material do emit secondary electromagnetic radiation in principle and of what approx. magnitude.

A14 The total radiated power will necessarily be lower than that of the original AMI source.

Q15 Please state how secondary EMR (induced by meter's data signal's EMR) could be tested for in house wiring and measured for power intensity and frequencies at certain home electrical outlets. Please state fairly priced testers.

A15 Even with very sophisticated and expensive equipment, such low levels of radio frequency energy would be difficult if not impossible to distinguish from the original signal from the meter, and other sources in the environment.

Q16 Please state whether each customer meter has its own frequency.

A16 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).

Q17 Please state whether neighbouring A, B, C customer meters frequencies could reach via the distribution line and service drops in another homes D in same street, thus travel all the house D wires.

A17 The energy from 100MHz and up frequencies is extremely unlikely to be picked up by distribution lines, to any significant extent, and even if they are picked up, they would dissipate well before reaching customer D wires.

Q18 Re Q17, if neighbour house D is indeed affected, how can frequencies from homes A, B and C be filtered out?

A18 Please see the response to Karow IR No. 3 Q17.

Q19 Please state whether the meters' frequencies are modulated. If so, please state all the modulation frequencies.

A19 Those AMI meters which use radio frequencies to transmit data all use some form of frequency modulation. The specific type of modulation varies between vendors, but the frequency range used is not likely to exceed +/- 10 MHz around the primary frequencies described in the response to Karow IR No. 1 Q13 (Exhibit B-2).