FORTISBC

David Bennett
Vice President,
Regulatory Affairs & General Counsel

FortisBC Inc.
Suite 100 - 1975 Springfield Road
Kelowna, BC V1Y 7V7
Ph: 250 717 0853
Fax: 866 605 9431
regulatory@fortisbc.com
www.fortisbc.com

February 26, 2008

Via Email
Original via Courier

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 CPCN for the Advanced Metering Infrastructure (AMI) Project No. 3698493

Please find enclosed FortisBC Inc.'s responses to Information Requests No.1 from the BC Utilities Commission, BCOAPO et al., Mr. Hans Karow, and Mr. Alan Wait. Twenty copies will be couriered to the Commission.

Sincerely,

David Bennett
Vice President, Regulatory Affairs
and General Counsel

cc: Registered Intervenors

1.0 Executive Summary

Reference: Exhibit B-1, Executive Summary, pp. 4-5

Q1.1 FortisBC intends to reduce the O&M component of its revenue requirements by the full amount of operational savings that result from AMI implementation. What mechanism(s) will FortisBC put in place to track and report on these reductions and compliance with this statement?

A1.1 FortisBC will provide information on the Project implementation annually as part of its revenue requirements application. As the majority of forecast net cost savings as shown in Table 4.1.1 at page 12 of the CPCN Application (Exhibit B-1), $2.491 million of $2.592 million, or 96 percent, will result from the elimination of the manual meter reading function, the Company considers that once the AMI is functional, O&M costs will have been reduced by that amount and there will be no requirement for further reporting in regard to this aspect.

FortisBC notes that the terms of its current PBR mechanism include an option to extend the mechanism to 2009, if the Company and its stakeholders so agree (pursuant to the Negotiated Settlement Agreement approved by Commission Order G-58-06). Net operating cost reductions will not occur until 2010, following the 2009 meter exchanges, and will be fully realized in 2011 on completion of the AMI Project. As stated, FortisBC intends to reduce the O&M component of revenue requirements by the full amount of operations savings, however the manner in which this is achieved will be dependent on the type of rate-setting mechanism in place in 2010 and future. The existing O&M formula could be adjusted to reduce O&M as follows:

Existing Base O&M Expense

=	Base O&M per customer	$382.48
times	Customer	100,000
=	Base O&M	$38.248 million

Adjusted Base O&M Expense

=	Existing Base O&M per customer	$382.48
less	AMI Adjustment per customer	
	[AMI savings 2.5 million / Customers 100,000]	- 25.00
=	Adjusted Base O&M per customer	357.48
times	Customers	100,000
=	Base O&M	$35.748 million

The final reduction to revenue requirements will be subject to (a possible Negotiated Settlement Process and) Commission approval.

Q1.2 FortisBC intends to provide customers access to consumption information to raise awareness and provide the tools necessary to conserve energy. Does the metering technology envisioned by FortisBC provide a real-time display of electricity prices and/or system consumption (with the purpose of highlighting periods when the system is under stress) to consumers? If not, why not?

A1.2 Following implementation, FortisBC will be able to provide customers access to their usage data and electricity costs in some manner such as a secure internet logon.

The real-time display of system consumption or electricity prices could be provided to customers over the internet today. This feature could be incorporated into the AMI system at a later date to support a Critical Peak Pricing program in the future.

2.0 Project Need

Reference: Exhibit No. B-1, 3. Project Need, Section No. 3.1, Description of the Existing System, p. 10

Q2.1 Please provide the annual cost for technical support of the existing hand held meter reading units.

A2.1 The average annual cost for technical support of the existing hand held meter reading units is $32,000.

Q2.2 Please provide the annual cost for support from internal IT resources.

A2.2 There are very minimal annual costs from internal IT resources relating to the hand-held meter reading units as FortisBC utilizes the manufacturer's (Itron) technical support line. It is estimated that internal support is less than 5 hours per month on average (less than $4,000 per year).

Q2.3 Please provide the meter reading cost per unit.

A2.3 Assuming that "meter reading cost per unit" means cost per meter reading, the cost per meter read performed in 2007 was approximately three dollars.

Q2.4 What is the increase in accuracy of the meter readings and will this increased accuracy reduce costs to the customer?

A2.4 Readings will be more accurate than the manual process as there is no chance for human data entry errors. Readings will be transmitted as data directly from the meter to the billing system virtually eliminating the possibility of misreads and keying errors. With the more accurate readings and reduced need for billing estimates that will be provided by AMI, it is estimated that billing related calls to FortisBC's contact center will decrease by approximately 25 percent resulting in a reduction of costs associated with these calls. The cost savings associated with the reduction in calls are expected to be $169,000 in the first year after implementation. In addition, billing corrections due to inaccurate readings will be almost completely eliminated. This will result in an additional cost savings of $96,000 per year for a total of $265,000 per year following Project completion.

Q2.5 What is the annual amount of decreased cost due to increased accuracy of the meter readings?

A2.5 Please refer to the response to BCUC IR No. 1 Q2.4 above.

3.0 Project Need

Reference: Exhibit No. B-1, 3. Project Need, Section No. 3.2, Customers Served, p. 10

Q3.1 Please provide in table format a listing, by rate schedule affected, of the number of meters to be deployed.

A3.1 Please see Table A3.1 below.

Table A3.1: Expected AMI Meter Installations by Rate Schedule

Rate Schedule	Number of Meters
1 – Residential	96,056
2 – Time-of-Use	7
20 – General Service	8,821
21 – General Service	1,926
22 – General Service Time-of-Use	6
60 – Irrigation	1,054
61 – Irrigation	3
2A – Time-of-Use	123
Total	**107,996**

4.0 Project Need

Reference: Exhibit No. B-1, 3. Project Need, Section No. 3.3, Summary, p. 11

"The primary limitations of the existing process are … Existing meters are not capable of adapting to non-standard rate structures"

Q4.1 Please explain the term "non-standard rate structures".

A4.1 In this context, "non-standard rate structures" are any rates other than flat rates and simple block rates. In particular, the CPCN Application is referring to rate structures in which the rate charged for power changes at certain times. One example of this type of non-standard rate structure is Critical Peak Pricing (CPP) where the price of electricity is dependent on the peak demand period which is usually identified 24 hours in advance.

5.0 Project Need

Reference: Exhibit B-1, Section 3.3, p. 11

Project Need - Summary

Q5.1 FortisBC states: "The costs of AMI technologies have declined to a point where these limitations can now be addressed with an AMI implementation." Please provide more information on how the costs of AMI technologies have evolved in recent years and anticipated future trends in the costs of AMI technologies.

A5.1 The quoted statement from the CPCN Application would have been more accurately stated as "Meter reading technology has advanced to a point where these limitations can be addressed in a cost-effective manner to the ratepayer". For roughly the same cost as the proposed AMI project, only drive-by remote metering reading technologies would have been available a few years ago and would not have provided the same magnitude of cost savings.

6.0 Project Description

Reference: Exhibit No. B-1, 4. Project Description, Section No. 4.1.1, AMI Benefits Yielding Operational Cost Savings, pp. 12-14

Q6.1 Is the FortisBC proposed system architecture diagram similar to the EPRI one below?

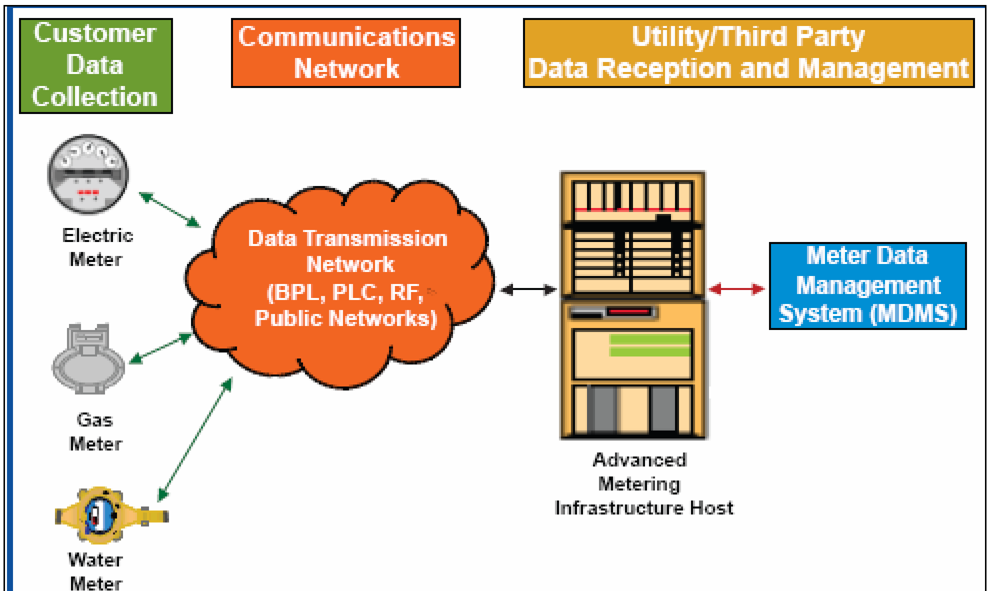


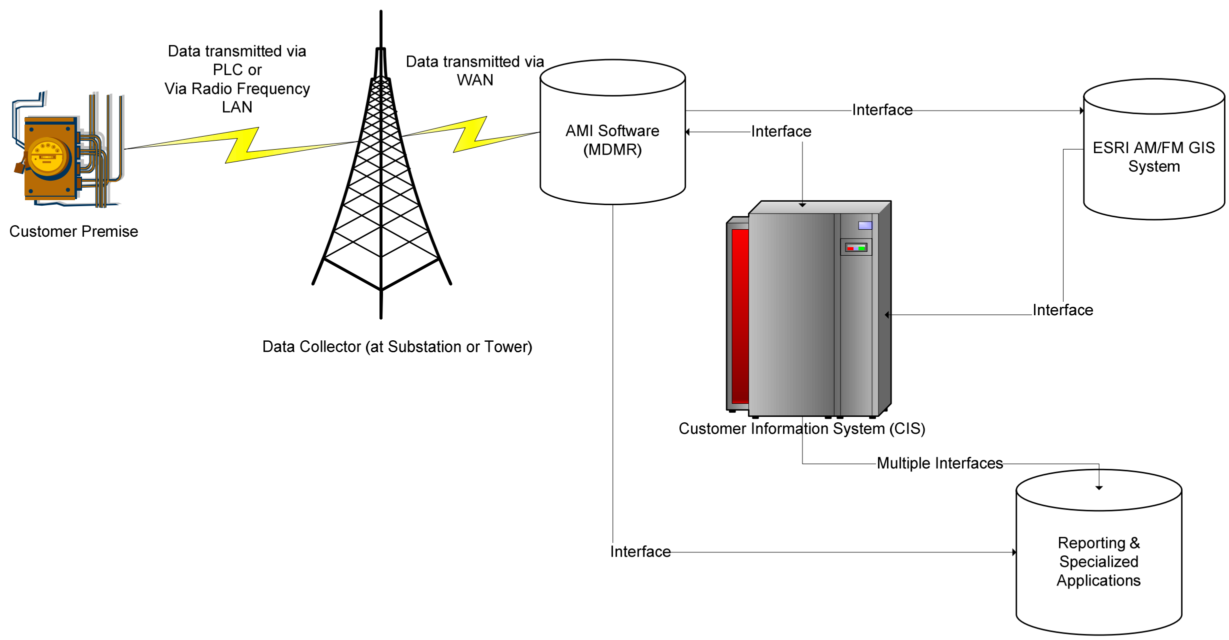
Figure 1: AMI Building Blocks[1]

A6.1 The building blocks of FortisBC's proposed AMI system are fundamentally the same as the diagram above with the exception of gas and water meters. The Advanced Metering Infrastructure project includes only the collection and communication of electric meter information, although it does specify that the system must be compatible with reading gas and water meters.

Q6.2 Provide a system architecture diagram showing the software and hardware interfaces.

A6.2 At a high level, the system infrastructure is expected to operate as displayed in Figure A6.2 below:

Figure A6.2: System Infrastructure



Q6.3 In Figure 1, the meter data is received by the AMI host system and then sent to the Meter Data Management System ("MDMS") that manages data storage and analysis to provide the information in useful form to the utility. Would FortisBC please explain how it proposes to provide the MDMS function within its current Application?

A6.3 The MDMS in FortisBC's application is referred to as a Meter Data Management Repository (MDMR). Costs and installation of the MDMR is provided in the Section 6.3 of the CPCN Application (Exhibit B-1). This software will act as the main repository for all data relating to the AMI system.

Q6.4 Since the ratepayers fund the project cost, please explain why these Total Net Annual Savings of $2.592 million should not be encumbered against the Operating and Maintenance budget for the duration of the payback period identified in the Application and then shared with the customer base on a 50/50 basis after the completion of the project payback.

A6.4 Please refer to the response to BCUC IR No. 1 Q6.5 below.

Q6.5 Please explain in detail if the commitment of page 4 of the Application to rebase O&M component will eliminate this issue.

A6.5 Yes, the issue is addressed by the reduction in the O&M component of the revenue requirements.

Q6.6 No system or line loss savings have been identifies. Please explain as there was some linkage with this issue in the Application for the Distribution Substation Automation Program.

A6.6 An AMI implementation, in conjunction with the Distribution Substation Automation Program, would allow a feeder-by-feeder analysis of actual distribution line losses. Once identified, a corrective action would have to be undertaken to actually reduce the loss. It is unknown at this point how much line loss savings could be realized as a result of this analysis. Therefore, no line loss savings have been identified.

Q6.7 Did FortisBC use Life-Cycle Costing ("LCC") to calculate the Annual Savings?

Q6.7.1 If yes, please provide the calculation.

Q6.7.2 If no, please provide the calculation and complete the table below.

	LLC of existing	**LLC of AMI**	**Annual Savings ($000s)**
Total Operating Labour (Incl. Benefits)			1,864
Total Non-Labour Operating			136
Vehicle Expenses			462
Handheld Support			29
Total Meter Reading Annual Cost Savings			**2,491**
Reduced Meter Exchanges			293
Outage and Restoration			25
Total Operations Annual Cost Savings			**318**
Reduced Calls Due to Billing Issues			169
Reduced Billing Errors Requiring Correction			96
Data Entry for Soft Reads			42
Total Customer Service Annual Cost Savings			**307**

A6.7 No, FortisBC used the annual cost of the existing process versus the annual cost of the AMI process to calculate annual savings for each year of the project life. Given that the expected lives of both the existing system and the AMI system are assumed to be approximately equal, life-cycle costing is not applicable. Please see Table A6.7 below.

Table A6.7: Annual Savings

	Annual Cost existing	Annual Cost AMI	Annual Savings
		($000s)	
Total Operating Labour (Incl. Benefits)	1,864	0	1,864
Total Non-Labour Operating	136	0	136
Vehicle Expenses	462	0	462
Handheld Support	29	0	29
Total Meter Reading Annual Cost Savings	**2,491**	**0**	**2,491**
Reduced Meter Exchanges	293	0	293
Outage and Restoration	25	0	25
Total Operations Annual Cost Savings	**318**	**0**	**318**
Reduced Calls Due to Billing Issues	676	507	169
Reduced Billing Errors Requiring Correction	102	6	96
Data Entry for Soft Reads	42	0	42
Total Customer Service Annual Cost Savings	**820**	**513**	**307**

7.0 Project Description

Reference: Exhibit No. B-1, 4. Project Description, Section No. 4.1.1.4 1 Operating Expenses AMI, p. 16

"Two additional IT resources will be required once the AMI deployment is complete. One resource will be responsible for maintaining the AMI database and producing reports and the other will be responsible for maintaining the communications infrastructure." ..."Ongoing communications costs relating to getting the AMI data back from the meters is expected to be approximately $142,000 per year."

Q7.1 Please justify in detail why two additional IT resources are required and especially why one will be maintaining the communications infrastructure when there are already ongoing communications costs of $142,000 per year identified.

A7.1 The ongoing communications costs of $142,000 per year relate to fixed and variable expenses required for data transmission (i.e. bringing data back from collectors to the MDMR). It does not include internal labour costs associated with maintaining the communications infrastructure. The IT resource allocated to this function is expected to be used to troubleshoot communications issues, work with the vendor as required, complete required maintenance as well as plan for the communications infrastructure to new developments within FortisBC's service territory. The second IT resource is required to maintain and support the new software and interfaces and to support system users in accessing and reporting on the new AMI data.

8.0 Project Description

Reference: Exhibit B-1, Section 3.1 (Description of Existing System), p. 10

FortisBC states that the current meter reading process has been reliable and has produced adequate results for customers. However, the implementation of an AMI system will allow the Company to achieve more accurate readings and reduce costs, while also providing further benefits to customers in the future.

Q8.1 What metrics does (and will) FortisBC use to establish the reliability and adequacy of its metering results for customers?

A8.1 FortisBC uses two performance metrics to establish the reliability of meter reading and the accuracy of customer bills. They are as follows:

- Meter Reading Accuracy is reflected as the percentage of meters that were read as scheduled; and

- Billing Accuracy is reflected as the percentage of bills delayed beyond their regular bill cycle due to errors.

It is anticipated that these metrics would continue to be used.

9.0 Project Description

Reference: Exhibit B-1, Section 4.1.3 (Future Benefits), pp. 22-23

Q9.1 Please provide any information available to FortisBC regarding the results of demand-side management programs implemented in conjunction with AMI programs.

A9.1 FortisBC has spoken to other utilities implementing AMI but did not receive any tangible results or details on the implementation of DSM programs in conjunction with their AMI implementation. As FortisBC reviews and prepares to update its DSM resource acquisition plan to meet its long-term goals, it is anticipated that the role for AMI-enabled programs will be addressed.

Q9.2 Based on this information, has FortisBC estimated the likely reduction in annual peak demand and/or energy that could be expected through this program?

A9.2 Please refer to the response to BCUC IR No. 1 Q9.1.

Q9.3 Please describe the results achieved with real-time load control by other implementers of AMI technology.

A9.3 Please refer to the response to BCUC IR No. 1 Q9.1.

10.0 Project Description

Reference: Exhibit B-1, Section 4.1.3, p. 22 Project Description - Future Benefits

Q10.1 Please provide examples of specific rate structures that would be possible following implementation of the AMI Project and some commentary on their likely relevance and benefits in the B.C. context.

A10.1 Two examples of rate structures that would be possible to implement following the AMI project are large scale Time-of-Use (TOU) and Critical Peak Pricing (CPP) rate structures. These rate structures have retail prices that vary depending on the time of the day or the time of year, allowing retail pricing that more closely tracks actual power purchase prices and encourages customers to change energy usage patterns. These types of rate structures could support the BC Energy Plan by potentially reducing or delaying the need for new generation and transmission infrastructure.

11.0 Environmental and Social Impact

Reference: Exhibit B-1, Section 5.7, p. 26 Environmental and Social Impact – Other Jurisdictions

Q11.1 Please provide copies of any cost–benefit analyses and/or rate impact analyses conducted to support implementation of the AMI Projects in Alberta and Ontario.

A11.1 Other than information provided in the publicly available regulatory documents provided as part of this Application, FortisBC is not aware of any cost-benefit and/or rate impact analyses.

12.0 Project Cost

Reference: Exhibit B-1, General

Economic Analysis

The Commission's recently published Decision concerning BC Hydro's 2006 IEP/LTAP states at pages 200-201:

"Typically the end result of a project evaluation is the expression of a PV or a levelized cost of energy or capacity. Both calculations require the use of a discount rate, and both calculations require a stream of cash flows to apply the discount rate to.

The Commission Panel accepts BC Hydro's argument that two tests may be considered for use in project evaluation. The first, and the more important, is an economic analysis of a project, which should only use the incremental cash flows disbursed by BC Hydro as its key input. The second, and less material test is a ratepayer impact analysis which examines how BC Hydro will recover a project's costs from its ratepayers and which may include items typically not found in a conventional economic analysis such as sunk costs, interest during construction and costs allocated from other departments of BC Hydro."

Please prepare and file an economic analysis (based in MS Excel) of the net benefits of the AMI Project relative to the status quo option. The economic analysis should include only *expected* annual cashflows over the life the project, with emphasis on cashflows that are expected to vary between the status quo and the AMI Project.

Ideally, the analysis should focus on the costs of each option. That is,

savings should be derived implicitly in the comparison of the two sets of cashflows. For example, operating costs associated with meter reading should be estimated for the status quo and for the AMI Project. The difference would then reflect the savings, if any, attributable to the AMI Project. Where this is not possible or overly cumbersome, FortisBC may in limited cases include savings as reductions to the AMI Project cashflows, but these should be broken out separately, reflect only incremental savings by year and input assumptions should be explicit. In all cases, the analysis should be structured to facilitate the sensitivity analyses described below. The distinction is not critical, but capital costs should reflect costs that would normally be capitalized. Operating costs should reflect costs that would normally be expensed in the year in which they are incurred. FortisBC may establish relevant categories of annual cashflows in preparing the model, but at a minimum, should be disaggregated into, but not limited to, the following categories:

Capital costs

- **Meter costs**
    - **Replacement**
    - **New**
- **Meter reading equipment**
- **Network infrastructure**
- **IT infrastructure and upgrades**
- **Project management**

Operating costs

- **Meter reading**
    - **Labour**

- **Non-Labour**
  - **T&D operating cost**
  - **Customer service**
  - **Income taxes. This may be incorporated as any significant incremental income taxes/savings (calculated on a flow-through "cash taxes" basis for simplicity) associated with the AMI Project.**

The capital costs of meters and other equipment should reflect expected additions and ongoing replacement costs, including consideration of the likely failure rate of different meters.

Meter reading costs under the AMI Project alternative should include any allowance for ongoing manual meter reading in early years, as well as any reasonable ongoing allowance for temporary manual meter reading labour.

Include a separate column in the model for annual GHG reductions associated with the AMI Project and the ability to attach an implicit value to these savings on a $/tonne basis which may then be deducted from other expenses (in sensitivity analyses).

All cashflows should be in real $2008 or any other suitable but common benchmark year.

Total capital expenditures should be included in the year in which they are expected to be incurred.

No financing or depreciation expenses should be included in the analysis.

Cashflows associated with the status quo should be estimated, together with cashflows associated with the AMI Project. The present value of all cashflows associated with each scenario should be calculated and the difference should indicate the net economic benefit associated with the AMI Project over the project life.

The discount rate should be a separate input to the model that can be

changed to test alternative assumptions.

The timeframe for the analysis should encompass the expected life of the AMI system meters. A terminal value may be included to reflect any residual or salvage value of assets at the end of the period. The assumptions used to derive any terminal value should be clearly stated in the commentary that accompanies the model.

The analysis should not include any sunk costs (e.g., depreciation expenses associated with existing meters), but may include capital replacement or upgrade costs (e.g., meter replacement costs in the status quo scenario).

The analysis should include likely changes in real cashflows over time, if any. Ideally, real escalation rates for key categories of costs would be specified outside the model so that these assumptions can be altered in sensitivity analyses.

The NPV analysis should be prepared using a real discount rate. The base case would use an ~8% discount rate (based on the 10% discount rate used in the Application and 2% general rate of inflation).

A brief commentary should be prepared to accompany the model that summarizes key input assumptions (e.g., labour rates and overheads, estimate of terminal values, etc.). The model should be structured to allow changes in key input assumptions for sensitivity analysis.

Prepare a base case analysis that reflects the relevant assumptions in the Application. Prepare also preliminary sensitivity analysis based on:

- **Deferring the AMI project one, three and five years. This analysis would include the costs associated with maintaining the current system in the first one, three and five years of the AMI Project cashflows, respectively. This should also consider possible**

reductions in AMI metering technologies over time.

- **Higher and lower real discount rates. One scenario should reflect FortisBC's allowed real weighted average cost of capital.**
- **Key cost uncertainties, including AMI meter costs, real labour and fuel escalation rates, and other key operating or capital costs with significant uncertainty.**

A12.0 As requested, please see the following base case Discounted Cash Flow (DCF) analysis and three sets of sensitivity analyses as follows:

- In Set "A" all values were expressed in real 2007 dollars;
- In Set "B" values were expressed in nominal dollars; and
- In Set "C" capital cost sensitivities were examined.

In all cases, except where otherwise noted, a discount rate of 8.0 percent has been used. However it should be noted that the Company's current after-tax Weighted Average Cost of Capital (WACC) is currently forecast to be 6.3 percent for 2008.

Furthermore, the Company is of the opinion that the correct cash flow for project evaluations is the incremental cash flow required from customers in the form of revenue requirements (the ratepayer impact analysis) not the incremental cash flow to the Company resulting from a particular project (the economic impact analysis). Therefore, if the economic impact analysis is determined to be the more important analysis, then the appropriate discount rate is the Company's WACC or 6.3 percent.

Income tax rates do not include the most recent 1.0 percent reduction in BC corporate tax rates proposed for July 1, 2008.

No financing or depreciation expenses are included in the analysis.

The base case assumes a 25 year modeling horizon with no terminal values.

Although the DCF model allows for the input of a GHG credit, the Company has not included an allowance in the analysis.

Set A – Real Dollar Sensitivities

As previously noted, in all scenarios under Set A values are expressed in real 2007 dollars.

Scenario A1 – Discount Rate Sensitivity

At an 8.0 percent discount rate, the discounted cash flow cost to the Company is approximately $3.3 million. The NPV when discounted at the Company's WACC of 6.3 percent is essentially break-even.

A1	**Discount Rate**	**6.3 Percent**	**8.0 Percent**	**10.0 Percent**
			(In Real $000s)	
	Status Quo	41,661	35,896	30,675
	AMI	41,688	39,164	36,776
	Net Benefit (Cost)	(27)	(3,268)	(6,101)

Scenario A2 – Labour Cost Escalation

Labour cost sensitivity was analyzed by holding all other costs in real dollars, and escalating labour costs in the first case by 1.5 and by 3.0 percent in the second case.

A2 Labour Cost Escalation	0.0 Percent	1.5 Percent	3.0 Percent
		($000s)	
Status Quo	35,896	39,608	44,205
AMI	39,164	39,659	40,233
Net Benefit (Cost)	(3,268)	(52)	3,972

Scenario A3 – Vehicle Cost Escalation

Vehicle cost sensitivity was analyzed by holding all other costs in real dollars, and escalating vehicle costs by 2.5 and 5.0 percent in two separate scenarios.

A3 Vehicle Cost Escalation	0.0 Percent	2.5 Percent	5.0 Percent
		($000s)	
Status Quo	35,896	37,308	39,340
AMI	39,164	39,209	39,254
Net Benefit (Cost)	(3,268)	(1,900)	86

Scenario A4 – General Inflation

General inflation sensitivity was analyzed by holding all other costs in real dollars, and applying a general inflation factor of 1.0 and then 2.0 percent.

A4 General Inflation	0.0 Percent	1.0 Percent	2.0 Percent
		($000s)	
Status Quo	35,896	36,446	37,077
AMI	39,164	39,564	40,030
Net Benefit (Cost)	(3,268)	(3,118)	(2,953)

Set B – Nominal Dollar Sensitivities

Set B values are expressed in nominal dollars and unless otherwise indicated are discounted at 8.0 percent. Sensitivity was examined by expressing all costs in nominal dollars using the following base case escalation factors and varying each nominal cost accordingly:

- Labour Cost Escalation 3.0 percent
- Vehicle Cost Escalation 5.0 percent
- General Inflation 2.0 percent

Scenario B1 – Discount Rate Sensitivity

Expressed in nominal dollars, the project provides a net benefit of $7.6 million at an 8.0 percent discount rate. The project is also beneficial at a discount rate of 10.0 percent and is marginally dilutive at a 12.0 percent discount rate.

B1	**Discount Rate**	**8.0 Percent**	**10.0 Percent**	**12.0 Percent**
			(In Nominal $000s)	
	Status Quo	48,830	40,637	34,495
	AMI	41,188	38,369	36,129
	Net Benefit (Cost)	7,642	2,268	(1,633)

Scenario B2 – Labour Cost Escalation

A change in the labour cost escalation estimate of plus or minus 1.0 percent improves or degrades the economic benefit of the project by approximately $3.0 million respectively.

B2	**Labour Cost Escalation**	**1. 0 Percent Lower**	**CPCN Application 3.0 Percent**	**1. 0 Percent Higher**
			(In Nominal $000s)	
	Status Quo	45,656	48,830	52,505
	AMI	40,797	41,188	41,622
	Net Benefit (Cost)	4,859	7,642	10,883

Scenario B3 – Vehicle Cost Escalation

A change in the vehicle cost escalation estimate of plus or minus 1.0 percent improves or degrades the economic benefit of the project by approximately $1.0 million respectively.

B3	**Vehicle Cost Escalation**	**1. 0 Percent Lower**	**CPCN Application 5.0 Percent**	**1. 0 Percent Higher**
			(In Nominal $000s)	
	Status Quo	47,926	48,830	49,883
	AMI	41,170	41,188	41,207
	Net Benefit (Cost)	6,756	7,642	8,676

Scenario B4 – General Inflation

A change in the general inflation estimate of plus or minus 1.0 percent improves or degrades the economic benefit of the project by approximately $0.2 million respectively.

B4	**General Inflation**	**1. 0 Percent Lower**	**CPCN Application 2.0 Percent**	**1. 0 Percent Higher**
			(In Nominal $000s)	
	Status Quo	48,200	48,830	49,555
	AMI	40,723	41,188	41,731
	Net Benefit (Cost)	7,477	7,642	7,823

Set C – Capital Cost Sensitivities

Capital cost sensitivities under Set C were examined by expressing the values in nominal dollars and varying the timing and capital cost of the project. All scenarios were analyzed using an 8.0 percent discount rate.

Scenario C1 – Defer the Project

Three scenarios were examined in this analysis:

- Defer the project one year
- Defer the project three years
- Defer the project five years

In each case the net benefit of the project is eroded due to the delay in realizing reduced operating costs associated with the project.

C1	Defer Project	CPCN Application	Defer One Year	Defer Three Years	Defer Five Years
		(In Nominal $000s)			
	Status Quo	48,830	48,830	48,830	48,830
	AMI	41,188	41,274	41,352	41,426
	Net Benefit (Cost)	7,642	7,556	7,479	7,404

Scenario C2 – Capital Cost Sensitivity

Capital cost uncertainty was analyzed at a macro level by varying the total capital cost by 10.0 and 20.0 percent around the CPCN estimates.

Every change of plus or minus 10 percent in the capital cost will decrease or increase the net benefit of the project by approximately $2.7 million respectively.

C2	Capital Cost	20% Lower	10% Lower	CPCN Application	10% Higher	20% Higher
				(In Nominal $000s)		
	Status Quo	48,830	48,830	48,830	48,830	48,830
	AMI	35,867	38,528	41,188	43,849	46,510
	Net Benefit (Cost)	12,963	10,302	7,642	4,981	2,320

Discounted Cash Flow Analysis
Net Benefit (Cost)

Line No.		NPV @ 8.00%	0 Dec-08	1 Dec-09	2 Dec-10	3 Dec-11	4 Dec-12	5 Dec-13	6 Dec-14	7 Dec-15	8 Dec-16	9 Dec-17	10 Dec-18	15 Dec-23	20 Dec-28	25 Dec-33
	Summary															
	Discounted Cash Flow															
1	**Capital Costs**															
2	Meter Costs															
3	New	**674**	0	110	97	79	61	62	62	61	60	59	57	49	34	35
4	Replacement	**16,111**	0	6,863	11,381	0	0	0	0	0	0	0	0	0	0	0
4		**16,785**	**0**	**6,972**	**11,478**	**79**	**61**	**62**	**62**	**61**	**60**	**59**	**57**	**49**	**34**	**35**
5	Meter Reading Equipment	**(455)**	0	0	0	0	0	(250)	0	0	0	0	(250)	(250)	(250)	(250)
6	Network Infrastrucuture	**5,586**	0	3,176	3,085	0	0	0	0	0	0	0	0	0	0	0
7	IT infrastructure and upgrades	**819**	0	1,242	144	0	0	(250)	0	0	0	0	(250)	(250)	(250)	(250)
8	Project Management	**2,315**	515	989	1,031	0	0	0	0	0	0	0	0	0	0	0
9		**25,050**	515	12,380	15,738	79	61	(438)	62	61	60	59	(443)	(451)	(466)	(465)
10	**Operating Costs**															
11	Meter Reading															
12	Labour	**(16,521)**	0	0	(407)	(1,657)	(1,680)	(1,703)	(1,726)	(1,749)	(1,772)	(1,794)	(1,815)	(1,913)	(1,986)	(2,052)
13	Non-Labour	**(5,291)**	0	0	(131)	(534)	(543)	(552)	(549)	(558)	(567)	(576)	(584)	(612)	(632)	(650)
14		**(21,812)**	0	0	(537)	(2,190)	(2,222)	(2,255)	(2,275)	(2,307)	(2,339)	(2,369)	(2,399)	(2,525)	(2,619)	(2,702)
15	T&D operating cost	**(1,842)**	0	0	0	(293)	(297)	(301)	(305)	(308)	(312)	(316)	(319)	(23)	(23)	(23)
16	Customer service	**1,744**	0	0	75	216	213	209	205	201	197	193	190	173	161	150
17	Income taxes	**128**	0	(312)	(673)	(551)	(338)	(185)	(67)	34	119	189	254	411	438	404
18		**(21,781)**	0	(312)	(1,136)	(2,818)	(2,645)	(2,532)	(2,442)	(2,381)	(2,335)	(2,303)	(2,275)	(1,964)	(2,043)	(2,172)
19	**GHG Reduction (217.6 tonnes)**															
20	**Net Cash Flow**	**3,268**	**515**	**12,068**	**14,602**	**(2,739)**	**(2,584)**	**(2,970)**	**(2,380)**	**(2,319)**	**(2,275)**	**(2,244)**	**(2,718)**	**(2,415)**	**(2,509)**	**(2,636)**
21	**Discounted Cash Flow**	**3,268**	**515**	**11,174**	**12,519**	**(2,174)**	**(1,899)**	**(2,022)**	**(1,500)**	**(1,353)**	**(1,229)**	**(1,123)**	**(1,259)**	**(761)**	**(538)**	**(385)**

Discounted Cash Flow Analysis
Option "AMI"

Line No.		NPV @ 8.00%	0 Dec-08	1 Dec-09	2 Dec-10	3 Dec-11	4 Dec-12	5 Dec-13	6 Dec-14	7 Dec-15	8 Dec-16	9 Dec-17	10 Dec-18	15 Dec-23	20 Dec-28	25 Dec-33
	Summary															
	Discounted Cash Flow															
1	**Capital Costs**															
2	Meter Costs															
3	New	**1,321**	89	200	178	145	112	114	113	112	109	107	104	90	62	64
4	Replacement	**16,111**	0	6,863	11,381	0	0	0	0	0	0	0	0	0	0	0
4		**17,432**	**89**	**7,063**	**11,558**	**145**	**112**	**114**	**113**	**112**	**109**	**107**	**104**	**90**	**62**	**64**
5	Meter Reading Equipment	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Network Infrastrucuture	**5,586**	0	3,176	3,085	0	0	0	0	0	0	0	0	0	0	0
7	IT infrastructure and upgrades	**1,274**	0	1,242	144	0	0	0	0	0	0	0	0	0	0	0
8	Project Management	**2,315**	515	989	1,031	0	0	0	0	0	0	0	0	0	0	0
9		**26,607**	604	12,471	15,818	145	112	114	113	112	109	107	104	90	62	64
10	**Operating Costs**															
11	Meter Reading															
12	Labour	**4,068**	1,549	1,590	1,220	0	0	0	0	0	0	0	0	0	0	0
13	Non-Labour	**1,303**	495	509	392	0	0	0	0	0	0	0	0	0	0	0
14		**5,370**	2,044	2,100	1,612	0	0	0	0	0	0	0	0	0	0	0
15	T&D operating cost	**1,786**	276	283	288	0	0	0	0	0	0	0	0	312	324	335
16	Customer service	**5,227**	262	269	350	497	497	497	497	497	497	497	497	497	497	497
17	Income taxes	**174**	0	(312)	(673)	(551)	(338)	(187)	(64)	37	122	192	256	417	448	418
18		**12,557**	2,582	2,339	1,577	(54)	158	309	432	534	619	689	752	1,226	1,269	1,250
19	**GHG Reduction (217.6 tonnes)**	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	**Net Cash Flow**	**39,164**	**3,186**	**14,810**	**17,396**	**90**	**270**	**423**	**546**	**646**	**728**	**796**	**856**	**1,315**	**1,331**	**1,314**
21	**Discounted Cash Flow**	**39,164**	**3,186**	**13,713**	**14,914**	**72**	**199**	**288**	**344**	**377**	**393**	**398**	**396**	**415**	**286**	**192**

Discounted Cash Flow Analysis
Option "Status Quo"

Line No.		NPV @ 8.00%	0 Dec-08	1 Dec-09	2 Dec-10	3 Dec-11	4 Dec-12	5 Dec-13	6 Dec-14	7 Dec-15	8 Dec-16	9 Dec-17	10 Dec-18	15 Dec-23	20 Dec-28	25 Dec-33
	Summary															
	Discounted Cash Flow															
1	**Capital Costs**															
2	Meter Costs															
3	New	**647**	89	91	81	66	51	51	51	51	49	49	47	41	28	29
4	Replacement	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4		**647**	**89**	**91**	**81**	**66**	**51**	**51**	**51**	**51**	**49**	**49**	**47**	**41**	**28**	**29**
5	Meter Reading Equipment	**455**	0	0	0	0	0	250	0	0	0	0	250	250	250	250
6	Network Infrastrucuture	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	IT infrastructure and upgrades	**455**	0	0	0	0	0	250	0	0	0	0	250	250	250	250
8	Project Management	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9		**1,557**	89	91	81	66	51	551	51	51	49	49	547	541	528	529
10	**Operating Costs**															
11	Meter Reading															
12	Labour	**20,588**	1,549	1,590	1,627	1,657	1,680	1,703	1,726	1,749	1,772	1,794	1,815	1,913	1,986	2,052
13	Non-Labour	**6,594**	495	509	523	534	543	552	549	558	567	576	584	612	632	650
14		**27,182**	2,044	2,100	2,149	2,190	2,222	2,255	2,275	2,307	2,339	2,369	2,399	2,525	2,619	2,702
15	T&D operating cost	**3,628**	276	283	288	293	297	301	305	308	312	316	319	335	347	358
16	Customer service	**3,483**	262	269	275	280	284	288	292	296	300	303	307	324	336	347
17	Income taxes	**46**	0	0	0	0	0	(2)	3	3	3	3	2	6	10	14
18		**34,339**	2,582	2,651	2,713	2,764	2,803	2,842	2,874	2,914	2,953	2,992	3,027	3,190	3,312	3,421
19	**GHG Reduction (217.6 tonnes)**	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	**Net Cash Flow**	**35,896**	**2,671**	**2,742**	**2,794**	**2,829**	**2,854**	**3,393**	**2,926**	**2,965**	**3,003**	**3,040**	**3,574**	**3,730**	**3,840**	**3,951**
21	**Discounted Cash Flow**	**35,896**	**2,671**	**2,539**	**2,395**	**2,246**	**2,098**	**2,309**	**1,844**	**1,730**	**1,622**	**1,521**	**1,655**	**1,176**	**824**	**577**

13.0 Project Cost

Reference: Exhibit No. B-1, 1. Application, p. 10

Revised Cost Estimate

FortisBC states that:

"Following Commission approval of the Application, the Company will issue a Request for Proposal (RFP) to vendors of AMI technologies, and expects to execute contracts for the Project during 2008. FortisBC will file a Revised Project Cost Estimate within 30 days of execution of all major contracts. If the Revised Project Cost Estimate exceeds 110 percent of the cost estimate set out in this Application, FortisBC will provide a detailed variance analysis and justification to the Commission."

Q13.1 If the Revised Project Cost Estimate exceeds 110 percent of the cost estimate set out in this Application, would FortisBC like to discuss whether or not it would be appropriate to require FortisBC to obtain a new CPCN that continues to be in the Public Interest?

A13.1 FortisBC does not believe that submission of a new CPCN Application should be required in this case. Please also refer to the discussion in the response to BCUC IR No. 1 Q13.2.

Q13.2 Would FortisBC please comment on whether or not a conditional CPCN should be sought that would allow FortisBC to submit a revised funding estimate (after the selection of the vendor but before the award) that would provide better definition to the project?

A13.2 FortisBC accepts that a conditional CPCN may be required for the AMI Project. After the granting of a conditional CPCN, and the conclusion of the RFP process, FortisBC would submit a revised funding estimate after the selection of the vendor. FortisBC proposes that should the RFP process produce a revised cost estimate not exceeding 110 percent of the CPCN costs, the final CPCN would be granted without further process. In the event that the revised estimate is greater than 110 percent of the CPCN cost, FortisBC will provide the Commission with a detailed variance analysis and justification.

14.0 Project Cost

Reference: Exhibit No. B-1, 1. Application, p. 10 Deferral Account for Existing Meters

FortisBC states that:

"FortisBC also requests an accounting order, consistent with the Canadian Institute of Chartered Accountants (CICA) Handbook, to defer the net book value, less proceeds of disposal, of the meters to be retired, and to amortize the deferred amount at the existing depreciation rate for meters, 3.5 percent."

Q14.1 Would FortisBC, please provide the net book value (of the remaining useful life of the existing meters to be retired early), and the estimate of the proceeds of disposal of these meters?

A14.1 Please see Table A14.1 below.

Table A14.1: Existing Meters Net Book Value

	As at December 31, 2007
Gross Book Value	$12,753,594
Accumulated Depreciation	(3,906,103)
Net Book Value	$8,847,491

An RFP will be issued for the disposal of the existing meter population. It is expected that this activity will be cost neutral with the cost for bins and transportation being offset by the value earned in the way of the scrap material.

Q14.2 Why did FortisBC, chose 3.5 percent for the existing depreciation rate for the meters?

A14.2 The 3.5 percent is the amortization rate recommended in the Company's 2005 Depreciation Study and approved by Commission Order G-58-06.

Q14.3 Would FortisBC consider writing off the net book value over say 5 years? If not, why not?

A14.3 Yes, the Company would consider writing off the net book value of the existing meters over 5 years. The longer amortization period was recommended in order to smooth the rate impact.

15.0 Project Costs

Reference: Exhibit No. B-1, 6. Project Costs, Section No. 6.1, Assumptions and Data Sources, p. 28

Q15.1 Please provide amortization policy in years for the smart meters, computer hardware, software, and communications network systems.

A15.1 The amortization rates for the various components are based on the accrual rates recommended in the Company's 2005 Depreciation study, as filed and approved by the Commission in Order G-58-06.

Meters	28.6 years	(3.5%)
Network infrastructure	16.7 years	(6.0%)
IT infrastructure and upgrades	16.7 years	(6.0%)

Q15.2 Please discuss the unit cost per system component of this proposal with respect to the following Electric Power Research Institute "Advanced Metering Infrastructure (AMI)".

A15.2 FortisBC assumes that the document cited above is the EPRI White Paper dated February 2007. In this White Paper, the average costs for an AMI implementation are noted as follows:

Endpoint Hardware	45%
Network Hardware	20%
Installation	15%
Project Management	11%
IT	9%

If the cost categories within the EPRI White Paper are aligned with those in FortisBC's CPCN Application, they can be compared as detailed in Table A15.2 below:

Table A15.2: AMI Estimated Component Cost

	FortisBC	**EPRI**
(i) Meters and Modules	64%	60%
(ii) Network Infrastructure	22%	20%
(iii) IT Infrastructure and Upgrades	5%	9%
(iv) Project Management	9%	11%

The percentage allocations between the EPRI paper and FortisBC's CPCN Application are comparable with slight differences related to Meters and Modules and the IT infrastructure costs.

Common reasons for price differences in the AMI costs between utilities include:

- The terrain, geographical layout and density of customers within the service territory can impact the costs of the required communications infrastructure;
- Business requirements and the associated AMI functions and features required to deliver on those benefits differ for different utilities. These differences in scope can impact the cost of the project;
- The installation cost per end point can vary dependent on the labour market in the service area, customer density, terrain, and the size of the customer base; and
- The inclusion and complexity of the MDMR can impact the overall cost of an AMI system. For example, most Ontario utilities do not require an MDMR as the Ontario Energy Board (OEB) will be developing and maintaining the MDMR system. Utilities that are implementing an MDMR with validation and estimation capability will have a higher IT cost than those with a basic MDMR.

Q15.3 Please discuss the Application on a unit cost per system component in comparison to both the Fortis Alberta Advanced Metering Infrastructure (AMI) Phase II – Full Deployment Business Case 2008/2009, Phase I Tariff Application, dated June 1, 2007.

A15.3 FortisBC does not have sufficient information regarding the FortisAlberta AMI Application to answer this question. General reasons for differences in AMI costs are presented in the response to BCUC IR No. 1 Q15.4.2.

Q15.4 In the Fortis Alberta Advanced Metering Infrastructure (AMI) Phase II – Full Deployment Business Case 2008/2009, Phase I Tariff Application, June 1, 2007; the total cost (shown in Table 3.3 below) to deploy substation hardware upgrades (There will be an installation of meter data collection equipment at 158 substations in 2008 to 2010.), AMI-enabled meter installations (FortisAlberta will deploy approximately 63,000 meters scheduled to begin in August of 2008, followed by 239,000 meters in 2009, and 103,000 meters in 2010.) Management of the transition from the current outsourced meter reading vendor. FortisAlberta re-negotiated the contract to support a seamless transition from manual meter reading to AMI-enabled meters and management of the transition from the current outsourced meter reading vendor (The contractual provisions include mechanisms for the meter vendor to flow through their costs to FortisAlberta and provide one-time incentive payments to meter readers to ensure they are retained until their areas are fully transitioned.).

Table 3.3 2008 - 2010 Forecast Capital Expenditures and Offsets
AMI Phase II Deployment

Description	Forecast 2008 ($000)	Forecast 2009 ($000)	Forecast 2010 ($000)	Total ($000)
Capital Expenditures				
AMI Phase II Meters	$6,993	$32,720	$14,661	$54,374
Meters 2007 Growth (for period January – December 2007 only)	1,578	279	0	1,857
Substation Hardware	4,041	4,262	1,107	9,410
Installation Costs	10,341	17,240	6,425	34,006
Subtotal Capital Expenditures	$22,953	$54,501	$22,193	$99,647
Capital Offsets				
Retrofit Meters	$(1,231)	$(1,449)	$0	(2,680)
Subtotal Capital Offsets	$(1,231)	$(1,449)	$0	$(2,680)
Net Capital Expenditures	**$21,722**	**$53,052**	**$22,193**	**$96,967**
Engineering and Supervision	1,737	3,979	1,665	7,381
Total Capital Expenditures	**$23,459**	**$57,031**	**$23,858**	**$104,348**

(Totals may vary due to rounding.)

Q15.4.1 Please explain the Unit Cost in Comparison to the FortisBC Application noting the cost differences and any explanations.

A15.4.1 FortisBC does not have sufficient information regarding the FortisAlberta AMI Application, including access to the confidential contracts that would be required to answer this question. General reasons for differences in AMI costs are presented in the response to BCUC IR No. 1 Q15.4.2.

Q15.4.2 In the Fortis Alberta Application, it appears that they can install 405,000 meters at an approximate installed cost of $ $234.41/meter for a total cost of $ $94,938,000 (only substation hardware was removed). Please explain why FortisBC requires $31,341,000 for 108,000 meters. The FortisBC Application is $290.19/meter. Please explain.

A15.4.2 The FortisBC application includes the communication infrastructure required to transmit data from the meter within the thirty one million dollar estimate. Therefore, for comparison purposes, the FortisAlberta costs should include the substation hardware which would have resulted in a cost of $257.65 per meter rather than the stated $234.41 per meter.

There are several items that could lead to the price difference on a per endpoint basis. For the discussion on these items please refer to the response to BCUC IR No. 1 Q15.2.

Q15.4.3 Please submit the Fortis Alberta Advanced Metering Infrastructure (AMI) Phase II – Full Deployment Business Case 2008/2009, Phase I Tariff Application, June 1, 2007

A15.4.3 Please find a copy of the requested documents attached as Appendix

15.4.3a and Appendix 15.4.3b.

Q15.5 In the “Hydro One Brampton Networks Inc. Issuance of Addendum for Smart Metering Rates To The 2007 Distribution Rate Adjustments ED-2003-0038 EB-2005-0377/ EB-2007-0541 Summary of Application February 9th, 2007”, please examine the unit costs and provide a comparison.

Q15.5.1 In the Hydro One Application, it appears that they can install 132,000 meters at an installed cost of $152.18/meter for a total cost of $20,087,560. Please explain why FortisBC requires $31,341,000 for 108,000 meters. The FortisBC Application is $290.19/meter. Please explain.

A15.5.1 FortisBC does not have sufficient information regarding the Hydro One AMI Application to answer this question. General reasons for differences in AMI costs are presented in the response to BCUC IR No. 1 Q15.2.

Q15.5.2 Please submit the “Hydro One Brampton Networks Inc. Issuance of Addendum for Smart Metering Rates To The 2007 Distribution Rate Adjustments ED-2003-0038 EB-2005-0377/ EB-2007-0541” - Summary of Application, February 9, 2007.

A15.5.2 Please find a copy of the requested document attached as Appendix 15.5.2.

Q15.5.3 Please provide a unit cost comparison for other examples of AMI installations.

A15.5.3 In a presentation given by eMeter Corporation at the CIS Conference in May of 2007, a range of costs for each of the following categories was identified:

Meter with Communications Module:
$50-$400 (dependent on the type of meter and the required functions)

Meter Installation:
$10-$200 (dependent on the type of meter, the density of the customer base and the labour market in the area)

Local Area Network (LAN):
$2-$50 (dependent on the technology type, the density of the customer base and the geographical terrain)

Wide Area Network (WAN):
$10 per LAN node per month (dependent on whether the network is privately owned or public domain)

AMI Data Infrastructure:
$0.25-$5.00 per meter per month (dependent on the complexity of the MDMR, state of the current applications, the state of the organization and required operating expenses post-AMI)

Project Overheads: 10-20 percent

Unit costs between utilities can vary significantly depending on these factors. For this reason, FortisBC believes that a detailed estimate process taking into account these factors as well as completing a competitive RFP process provides a competitive and more accurate price than that provided by comparing unit costs with other utilities.

16.0 Project Cost

Reference: Exhibit No. B-1, 6. Project Costs, Section No. 6.3, Cost Details, p. 29

Q16.1 Please confirm the estimate is in Nominal (As-spent) dollars, or provide it on a Nominal basis.

A16.1 The total capital costs are confirmed to be in nominal dollars.

Q16.2 Please identify the exclusions and assumptions made to perform this estimate.

A16.2 In addition to those listed in Section 6.1 of the CPCN Application (Exhibit B-1), the following exclusions and assumptions were made to perform this estimate:

Assumptions:

- Approximately 10 percent of premises are difficult to access and will require more than one visit; and
- At least 90 percent of meters are located outdoors.

Exclusions:

- Cost estimates do not include the implementation of any future benefits discussed in Section 4.1.3 of the CPCN Application (Exhibit B-1).

Q16.3 Would FortisBC please explain the cost estimating technique used to develop this estimate?

A16.3 Please refer to the response to BCUC IR No. 1 Q16.4.

Q16.4 Please describe the cost estimate review process performed by FortisBC.

A16.4 Two vendors representing the two main technologies were selected for cost comparison purposes. Each vendor was provided with details on FortisBC's meter population and existing infrastructure. This information included latitude and longitude coordinates of all meters, types of meters in the field, substation information and the location of communications towers in the area. They were also provided the high level list of required functions listed in Table 7.1 of the CPCN Application (Exhibit B-1). Based on this information, each vendor created a detailed pricing estimate including a detailed listing of the required equipment. The cost estimates, benefits and project scope were reviewed by the AMI consultant who also organized the required costs by year of implementation and based on implementation experience, added additional costs as necessary.

Estimates of FortisBC's internal costs were developed and provided to the consultant to ensure the most accurate estimates possible.

Once both vendor and internal cost estimates were completed, estimates were reviewed to ensure the estimate was as complete and accurate as possible.

The estimates for each of the two technology options were within 3 percent of each other, with the higher of the two being used as the estimate within the CPCN Application.

Q16.5 Has FortisBC conducted an external review of this cost estimates and project scope using an independent third party?

A16.5 FortisBC retained an experienced AMI consultant to assist in the estimating process. This consultant reviewed the vendor estimates and the internal FortisBC costs as well as the project scope.

Q16.6 Please provide the estimate accuracy and estimate class based on the five cost estimate classifications by Association for the Advancement of Cost Engineering (AACE"), Recommended Practice for Classifying Cost Estimates.

A16.6 The estimate is best classified by separating the vendor quoted costs from the estimated internal costs provided in the response to BCUC IR No. 1 Q28.4.

Vendor Costs: The vendor costs were based on a reasonably detailed understanding of FortisBC's customer base, associated infrastructure and business requirements. For this reason, these costs would fall under Class Three within the AACE recommendations for classifying cost estimates. As Class Three (+/- 10 to 30 percent).

Internal Costs: The internal FortisBC costs relate to software development and project management. Detailed specifications for the required software cannot be completed until a final technology choice has been made. Instead, FortisBC utilized previous experience with software development and industry averages to create the estimate for internal costs. Because the level of detail is less than what was completed for the vendor costs, these costs would fall under Class Four within the AACE recommendations for classifying cost estimates. As Class Four (+/- 15 to 60 percent).

Q16.7 Would FortisBC please complete the risk matrix and assign a rating to each risk area: high, medium, or low, and a qualitative assessment of its relative impact and the likelihood of its occurrence and include the magnitude cost of each item?

RISK MATRIX TABLE

WBS	Technical Risks	Schedule Risks	Cost Risks	Resource Risks	Management Processes Risks

A16.7 As background information, FortisBC has prepared the following tables to define the terms used in this response:

Table 16.7a - Likelihood of Risk to Occur During the Project

Table 16.7b - Relative Impact Rating to the AMI Project

Table 16.7c - Net Classification of the Risk to the Project

Table 16.7a - Likelihood of the Risk to Occur During the Project

	Description	Criteria
1	Rare	May occur only in exceptional circumstances.
2	Unlikely	Could occur at some time/the event has not yet occurred but could occur at some time.
3	Possible	Might occur at some time/the event could occur once in your career or could occur at any time.
4	Likely	Will probably occur in most circumstances/the event has occurred several times or more in your career.
5	Almost Certain	Is expected to occur in most circumstances/will occur on an annual basis or more frequently.

Table 16.7b: Relative Impact Rating to the AMI Project

	Description	Criteria
1	Insignificant	The consequence would not threaten the scope or schedule of any aspect of the project and would be dealt with on a routine basis. Event results in a financial impact to the project of less than $5,000.
2	Minor	The consequences would threaten the scope and/or schedule of some aspect of the project but would be dealt with internally. Event results in a financial impact to the project of less than $10,000.
3	Moderate	The consequences would not threaten the success of the project but could affect scope and/or schedule. Event results in a financial impact to the project of greater than $50,000.
4	Major	The consequences would have a significant impact on the project's scope, cost and/or schedule. Event results in a financial impact to the project greater than $450,000.(>1.5% <10% of project cost)
5	Severe	The consequences would threaten the overall success of the project's quality, scope cost and/or schedule. Event results in a financial impact to the project greater than $3,000,000 (>10% of project cost)

Table 16.7c - Net Classification of the Risk to the Project

Net risk – Likelihood vs. Impact Ratings					
LIKELIHOOD	**IMPACT**				
	Insignificant	**Minor**	**Moderate**	**Major**	**Catastrophic**
Almost Certain	Medium	Medium	High	High	High
Likely	Medium	Medium	High	High	High
Possible	Low	Medium	Medium	High	High
Unlikely	Low	Low	Medium	Medium	Medium
Rare	Low	Low	Low	Medium	Medium

Using the preceding information, the table provided by the Commission is completed in the following format for each Work Breakdown Structure (WBS) Element:

Net Risk (Likelihood, Impact)

Table 16.7d: Risk Matrix

WBS Element	Technical Risk	Schedule Risk (4)	Cost Risk (4)	Resource Risk	Management Processes Risk
1.1 CPCN Application approval	Low (1, 1)	Med (3, 3)	Low (2, 2)	Low (1, 2)	Low (1, 1)
1.2 Complete RFP	Low (1, 1)	Low (3, 3)	Low (2, 1)	Low (1, 1)	Low (1, 1)
1.3 Create Final Schedule & Budget	Low (1, 1)	Low (1, 1)	Low (2, 2)	Low (1, 1)	Low (1, 1)
1.4 Assign / Hire Resources	Low (1, 1)	Low (2, 3)	Low (2, 3)	Low (3, 3)	Low (1, 1)
3.1 Create Interfaces	Med (2) (3, 3)	Med (3, 3)	Med (3, 3)	Low (1, 2)	Low (2, 2)
3.2 Install Required Hardware	Low (1, 1)	Low (1, 1)	Low (1, 1)	Low (1, 1)	Low (1, 1)
3.3 Install MDMR	Low (2, 3)	Low (2, 3)	Low (1, 1)	Low (1, 1)	Low (1, 1)
3.4 Install Communications Infrastructure	Med (3) (3, 3)	Med (2, 4)	Low (2, 2)	Low (2, 3)	Low (2, 3)
3.5 Billing System Enhancements	Low (2, 1)	Low (3, 1)	Low (3, 2)	Low (1, 3)	Low (1, 1)
3.6 Exchange Meters	Med (1) (3, 3)	Med (3, 3)	Low (2, 2)	Med (3, 3)	Med (3, 3)
4.1 Employee training	Low (2, 2)	Low (1, 1)	Low (2, 2)	Low (1, 1)	Low (1, 1)
4.2 Operational Processes Updates	Low (1, 1)	Low (1, 1)	Low (2, 2)	Low (1, 1)	Med (3, 3)
4.3 Technical Documentation Completed	Low (2, 2)	Low (2, 2)	Low (2, 2)	Low (1, 3)	Low (2, 2)

1 *Note that the superscript numbers are related to the response to BCUC IR No. 1 Q16.8.

Q16.8 Please provide a risk and contingency analysis based on at least these five risk factors: technical issues, design completion and maturity, equipment/vendor, construction cost, and construction schedule. Please provide an impact magnitude cost for each item listed and include in risk matrix table.

A16.8 As part of the project planning process, a detailed risk response plan will be created to encompass all identified risks, response strategies for those risks (including contingency cost estimates) and assignment of resources responsible for managing the risk. For the purposes of the creation of this Application and the compilation of the estimate, the following risks were considered as outlined in Section 7.3 of the CPCN Application (Exhibit B-1).

The probability/impact analysis related to each of these can be found in the response to BCUC IR No. 1 Q16.7 beside the corresponding footnote.

Technical Issues / Equipment / Vendor / Maturity:

[(1)] **Batch failures of the AMI Meters:** Although failures of individual meters are possible, a batch failure is unlikely to occur. The installation process will include verification of the communication path between the meter and the AMI software to confirm it is functional prior to the field technician leaving the site. This will reduce the cost impact of a failure since a return visit will not be required.

[(2)] **Interfaces are more complex than estimated:** Because a specific vendor has not been chosen for the AMI infrastructure and software, a detailed design cannot yet be completed for the required software interfaces. However, to mitigate this risk, FortisBC utilized prior experience with implementing similar software programs to create the estimate and had the external consultant verify this estimate based on their AMI experience.

(3) **Large Scale Failure of the Communications Infrastructure:** Most AMI systems have enough internal memory within the system to store several weeks of data. In most cases, the failure would be corrected prior to any data being lost. This risk will be mitigated through the use of meter readers throughout the implementation phase and post-implementation, meter readers could be recruited on a temporary basis to read meters if required.

During the RFP process, FortisBC will be looking for technology that is proven in the field and will be requiring system reliability commitments from vendors. References from other utilities that have already implemented this technology including a site visit to those utilities will also be important to verify that the AMI system is reliable and delivering on the benefits sought out by that utility.

(4) **Construction Costs and Schedule:**

Once a vendor has been chosen, the project schedule and cost estimates can be refined into a more detailed Work Breakdown Structure (WBS). Based on other utilities' AMI experience and the AMI consultant's expertise, FortisBC feels that the cost and schedule estimates provided in the Application are reasonably accurate.

To mitigate the risk during implementation, milestones for both internal and vendor resources will be monitored and tracked to ensure schedule adherence and to identify any issues early. In addition, a formal change management process will be part of the Project process to ensure that the cost and schedule is not impacted by changes in the scope of the Project during implementation.

Q16.9 Please provide escalation (including inflation) analysis.

A16.9 Please refer to the response to BCUC IR No. 1 Q27.3.

Q16.10 Please provide the estimated unit cost for:

Q16.10.1 Unit Cost per smart meter by rate schedule

A16.10.1 FortisBC feels that releasing this level of detail in regards to the cost estimate would jeopardize the RFP process and prevent the Company from obtaining the most competitive pricing available. However, this information will be provided in confidence if the Commission deems it is necessary at this stage.

Q16.10.2 Smart Meter Installation cost (estimated labour time and material cost per meter)

A16.10.2 Please refer to the response to BCUC IR No. 1 Q16.10.1.

Q16.10.3 Smart Meter Other Cost (estimated cost to repair broken meter bases, assuming an X% occurrence for broken meter bases).

A16.10.3 The estimated cost to repair broken meter bases has been included in the cost category “Meters and Modules” and is a total of $200,000 assuming a 0.4 percent occurrence rate during deployment.

Q16.10.3.1 Provide an assumption for the percent occurrence of broken meter bases.

A16.10.3.1 The occurrence rate for broken meter bases is assumed to be 1 in 250 which has been the experience of utilities in Ontario that have started deployment of Smart Meters.

Q16.11 Provide industry benchmarks or historical cost data to confirm the unit costs provide for the FortisBC smart meter costs.

A16.11 Please refer to the responses to BCUC IR No. 1 Q15.2 and Q15.5.3.

Q16.12 Please complete the Table 6.3, Summary of Capital Costs and provide the missing data and add any new line items.

Table 6.3: Summary of Capital Costs

		Direct Cost	**Indirect Cost**	**Total**
		($000s)	**($000s)**	**($000s)**
(i)	Meters and Modules			19,507
(ii)	AMI Vendor Training			41
(iii)	Network Infrastructure			6,700
(iv)	IT Infrastructure and Upgrades			1,483
(v)	MDMS – Meter Data Management System			
(vi)	Project Management • Project Management • 4 Project Leads • AMI Consultant • Business Analysis			2,000
(vii)	Existing Meter Removal Cost			
(viii)	Project Planning, Network Design, and Testing			660
(ix)	AFUDC			950
(x)	Escalation (including Inflation)			
Performance Measurement Baseline ("PMB")				**31,341**

Table 6.3: Summary of Capital Costs

		Direct Cost	**Indirect Cost**	**Total**
		($000s)	**($000s)**	**($000s)**
(xi)	Management Reserve			
Total Allocated Budget ("TAB")				**31,341**
(xii)	Other Non-Project Costs			
(xiii)	Regulatory Costs			
(xiv)	Contingency			
Total Project Cost ("TCP")				**31,341**

Non-Project and Future Costs				
	Incremental Meter Costs			1,336
	Incremental Metering Operational Expenses			
	Incremental Other Operational Expenses			
	Incremental Other Admin Expenses			
	Avoided Future Capital Costs			(1,250)
	Innovative Rate Structures			3,000
	Load Control			500
	Remote Disconnect/Reconnect for 108,000 meters at $199 ea.			21,492
	Meter Reading Frequency			
				$24,992

A16.12 The capital cost summary in a format similar to that requested is provided in

Table A16.12 below.

Table A16.12: Capital Cost Summary

	Direct Cost	Indirect Cost	**Total**
	($000s)		
Meters and Modules	16,086	1,175	**17,261**
SMI Vendor Training	35	3	**37**
Network Infrastructure	5,537	404	**5,942**
IT Infrastructure and Upgrades	976	71	**1,047**
MDMR - Meter Data Management Repository	260	18	**279**
Project Management	1,634	122	**1,757**
Network Design and Testing	552	40	**591**
AFUDC	-	876	**876**
Subtotal	25,080	2,710	**27,790**
Contingency	2,583	181	**2,764**
Escalation	714	49	**763**
Baseline Capital Budget	3,297	230	**3,527**
Regulatory	25	-	**25**
Other Non-Project Costs	-	-	-
Total Project Budget	28,402	2,940	**31,342**

FortisBC has not provided detail on the items listed as “Non-Project and Future Costs”. The Company has not identified the cost of rate design or demand side management initiatives that may arise in future, nor can the costs to implement a remote disconnect/reconnect feature be estimated. FortisBC expects that this initiative would likely be strategically deployed, if economic, only in hard-to-reach areas or at premises with chronic disconnection issues rather than on the entire meter population of 108,000.

The incremental metering and other operational and administration expenses are provided in detail, on an annual basis, at pages 12 to 16 of the CPCN Application (Exhibit B-1).

17.0 Project Cost

Reference: Exhibit No. B-1, 6. Project Costs, Section No. 6.3, Cost Details, (i) Meter and Modules, p. 30

Q17.1 Using the format and row items of the table above, please provide a table of the annual costs per year to completion.

A17.1 Please see Table A17.1 below

Table A17.1: Summary of Capital Costs

	2008	2009	2010	**Total**
	($000s)			
Meters and Modules	-	6,991	10,271	**17,261**
SMI Vendor Training	37	-	-	**37**
Network Infrastructure	-	3,003	2,939	**5,942**
IT Infrastructure and Upgrades	-	912	135	**1,047**
MDMR - Meter Data Management Repository	-	279	-	**279**
Project Management	445	352	959	**1,757**
Network Design and Testing	-	591	-	**591**
AFUDC	16	379	480	**876**
Subtotal	**499**	**12,507**	**14,784**	**27,790**
Contingency	49	1,217	1,498	**2,764**
Escalation	-	223	540	**763**
Baseline Capital Budget	49	1,440	2,038	**3,527**
Regulatory	25	-	-	**25**
Other Non-Project Costs	-	-	-	**-**
Total Project Budget	**573**	**13,947**	**16,822**	**31,342**

Q17.2 What is the number of projected new customers to be added to the FortisBC Service Area over the life of this project and have these new meters been included in the cost of this project?

A17.2 The incremental cost of the AMI meter versus a regular meter have been included in the cost of this project under “Non-Project Costs” described in Section 6.3 of the CPCN Application (Exhibit B-1). These costs are based on the assumption that between the period of 2009 and 2033, FortisBC will add approximately 36,000 new customers.

Q17.3 Please provide:

Q17.3.1 Please provide an explanation of useful life, depreciable life, economic life, certified life, and technological life as it relates to this proposal.

A17.3.1 **Useful Life:** The useful life is defined as the period of time that the components of the AMI system are able to perform their designed functions accurately and reliably. This is also sometimes referred to as "functional" life or "service" life.

Depreciable Life: The depreciable life is period of time over which the AMI system will be fully depreciated.

Economic Life: The Economic life is defined as the period of time that the AMI system are within the "Useful" life period and a new system would not be less expensive to implement and maintain.

Technological Life: The Technological Life is the period of time that the AMI system is considered to be modern and possesses most of the functionality available in newer systems on the market.

Certified Life: FortisBC is not familiar with this terminology but assumes that it is the period of time that the manufacturer guarantees the product will operated as designed.

Q17.3.2 The life of the meter and the replacement cost using the life definitions above, and

A17.3.2 For the purposes of this application, the Useful Life and Depreciable Life have been set at 25 years as per the 2005 Depreciation Study. The replacement cost of the AMI system after that period of time is difficult to speculate given how far in the future it will occur.

Q17.3.3 The Measurement Canada certified life and the re-certification costs, and

A17.3.3 Please refer to the responses to BCUC IR No. 1 Q22.1 and Q22.3.

Q17.3.4 Please provide the battery life and the battery replacement costs per meter (including labour).

A17.3.4 Not all AMI enabled meters utilize a battery within the meter. As part of FortisBC's RFP process, vendors will be expected to provide technology that either does not contain a battery or, if it does, the battery must have an expected life of at least twenty five years. Meters requiring a battery replacement will need to be exchanged and re-sealed at an approximate average cost of $265 / meter.

Q17.3.5 Changes to National Policy (E-26), "Reverification Periods for Electricity Meters and Metering Installations", issued September 15, 2004 by Measurement Canada, will result in increased frequency of mechanical demand meter exchanges. The proposed regulation will require that 100 percent of mechanical demand meters be exchanged every four years. In contrast, an average 7 percent of electronic demand meters (such as AMI) need to be sampled after ten years and then again after another six years.

Mechanical demand meters will require four complete exchanges in the timeframe that electronic demand meters will require only two sample exchanges. Has FortisBC included the cost of sampling these electronic meters in their Application? If not, why not?

A17.3.5 FortisBC has included the cost of sampling these electronic meters in the CPCN Application beginning in year ten. The costs are outlined as reduced savings on line 29 in the revenue requirements worksheet from the CPCN Application (Exhibit B-1).

Q17.3.6 Has FortisBC included this item in its cost benefit analysis?

A17.3.6 Please refer to the response to BCUC IR No. 1 Q17.3.5.

Q17.3.7 Was this expense cost allowed for in the revenue requirements template?

A17.3.7 Please refer to the response to BCUC IR No. 1 Q17.3.5.

18.0 Project Cost

Reference: Exhibit No. B-1, 6. Project Costs, Section No. 6.3, Cost Details, (ii) Network Infrastructure, p. 30

"From the two AMI technologies examined, FortisBC has identified three AMI solutions. All of these solutions will provide the benefits described in this Application. The AMI technology solutions contained within this application are focused on proven technologies that have been thoroughly field tested. These are Power Line Carrier, Radio Frequency, and a Hybrid Solution (Exhibit No. B-1, p. 44)."

Q18.1 Please provide the estimated cost per end-point for each of the three mentioned technologies.

A18.1 The estimated total cost per end-point for PLC technology is $290/meter. The estimated cost per end-point for RF technology is $281/meter. A detailed estimate was not created for the Hybrid solution.

Q18.2 Please provide the breakdown of the costs associated with the $6.7 million for Network Infrastructure by type of technology.

A18.2 As stated in the response to BCUC IR No. 1 Q16.10.1, FortisBC feels that releasing this level of detail in regards to the cost estimate would jeopardize the RFP process and prevent the Company from obtaining the most competitive pricing available. However, this information will be provided in confidence if the Commission thinks it is necessary at this stage.

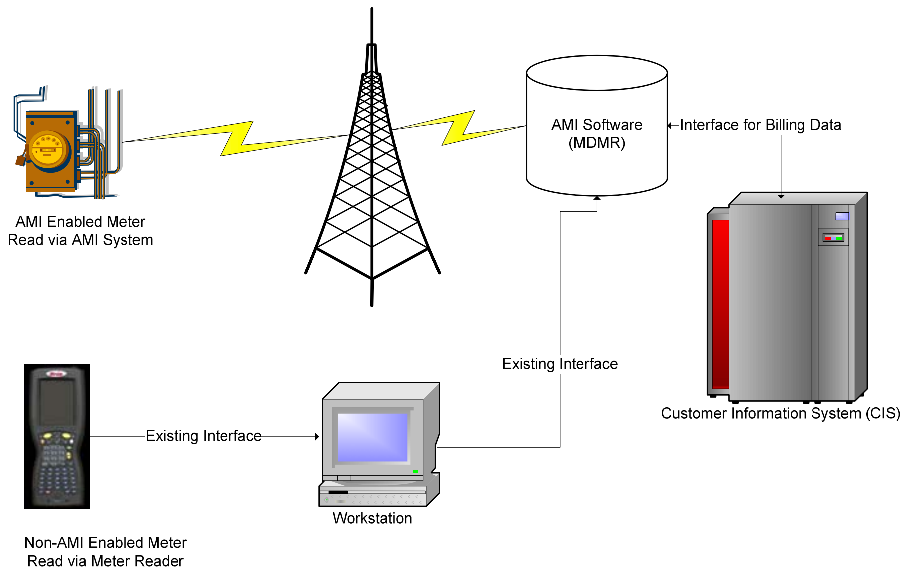
19.0 Project Cost

Reference: Exhibit No. B-1, 6. Project Costs, Section No. 6.3, Cost Details, (iii) IT Infrastructure and Upgrades, pp. 30-32

Q19.1 Please explain further how "the AMI software will be implemented in the initial stages of the project and parallel readings (both from the meter readers and the AMI system) during the transition will be filtered through this system". Will this require manually data entry into these systems?

A19.1 The AMI software and CIS Interface will be implemented in the first phase of the project. The existing interface between the hand-held meter reading units and the CIS system will be re-directed to flow through the AMI system first. The CIS interface will then transfer readings from the AMI software when needed for billing to the CIS billing system via the new interface. The upload process for the manual meter readings will work essentially as it does now and there will be no additional requirement for manual data entry other than what is required to enter the readings into the handheld devices. Please see Figure 19.1 below for an illustration of the proposed process.

Figure 19.1: Proposed AMI Process



Q19.2 Provide costs for:

Q19.2.1 An interface between the AMI software and the CIS System;

A19.2.1 The cost of an interface between the AMI software and the CIS System is expected to be bi-directional including the importing of billable reads into the CIS system and synchronizing customer data between the AMI software and the CIS system. The cost of this interface is estimated at $161,000.

Q19.2.2 An interface to synchronize the customer information in the AMI

A19.2.2 This cost is included in the AMI / CIS interface. The estimate is provided in the response BCUC IR No. 1 Q19.2.1

Q19.2.3 An interface from the AMI software and the Company's field mapping system software to the interface in CIS.

A19.2.3 The cost of the interface between the AMI software and the Company's field mapping system is expected to cost $118,000.

Q19.3 Provide a typical listing of the work orders that would be automatically generated by the Work Order Management Interface.

A19.3 The Work Order Management interface is expected to take data from work orders generated by the installation contractor during the AMI installation and import them into FortisBC's billing system. The typical work order types that would be included are meter exchanges, installations and removals.

Q19.4 What is the expected cost saving for this Work Order Management Interface and was it taken into account?

A19.4 There is no cost savings associated with this interface. The interface as described in the CPCN Application will not be a complete Work Order Management System that coordinates all types of field orders, schedules them and interfaces that data into the various systems. Instead, it is expected that the installation vendor will have a Work Order Management system already in place that they will utilize to manage the installation. FortisBC will create an interface from that system to automatically update meter data within the CIS Billing System. This interface is expected to be used only during the implementation of AMI and to cost $235,000.

Q19.5 Please provide a listing of the additional hardware required to support the AMI software and its expected cost.

A19.5 The $128,000 identified for hardware to support the AMI software is comprised of the following equipment and expected costs:

- Two IBM AIX servers at $50,000 each, totaling $100,000; and
- Two HP Microsoft Servers at $14,000 each, totaling $28,000.

These requirements are based on general specifications provided by the vendors.

20.0 Project Cost

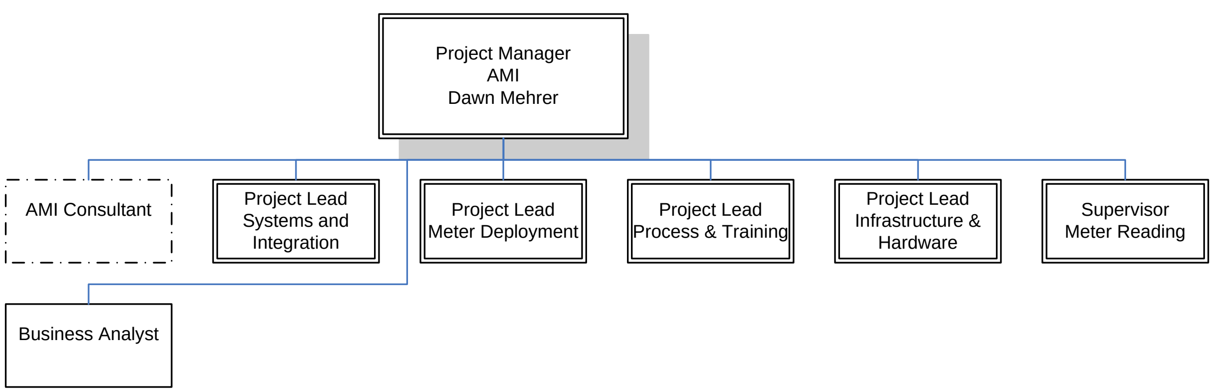
Reference: Exhibit No. B-1, 6. Project Costs, Section No. 6.3, Cost Details, (iv) Project Management, p. 33

Q20.1 Please provide a project organization chart for the Application with names.

A20.1 Other than the Project Manager, resources have not yet been specifically assigned to the AMI project. It is expected that these roles would be filled following approval of the CPCN Application.

The expected organizational chart is shown below in Figure A20.1:

Figure A20.1: Organizational Chart



Q20.2 Please identify the roles to be performed by the four project lead resources.

A20.2 The expected roles of the four lead project resources are as follows:

Project Lead, Process and Training

The Project Lead, Process and Training will be responsible for the following portions of the implementation of AMI at FortisBC:

- Identify the processes that will be impacted by AMI and organize them into a schedule based on timing of impact (pre-deployment, during deployment or post-deployment);
- Work with process owners to document process changes, update audit documentation as required and ensure the changes are implemented at the appropriate time;
- Work with the regulatory department on any tariff changes or clarifications that may be required during the roll out of the project;
- Ensure compliance / safety training for all contracted or internal staff working on the roll out;
- Identify AMI related training requirements, develop and provide training to internal staff on AMI processes, the project and key messages related to the project; and
- Track promised benefits of the business case to ensure process changes support these benefits and the benefits can be realized post-implementation.

Project Lead, Systems and Integration

The Project Lead, Systems and Integration will be responsible for the following portions of the implementation of AMI at FortisBC:

- Develop and manage cost and time schedules for approximately $1.5 million in AMI related software, specifically:

    - AMI Meter Data Management Software;
    - Ad hoc and standard reporting related to AMI data;
    - Interface to the CIS System for billing purposes (bi-directional to MDMR);
    - Upgrade to the CIS system for interval billing;
    - Interface to the ESRI mapping system; and
    - Work order management tool integration.
- Gather, review and communicate functional requirements for each of the software integration products;
- Communicate and receive sign-off from stakeholders on the requirements for each individual software project;
- Manage any outsourced portions of software development to ensure Service Level Agreements (SLA) and quality requirements are met;
- Develop a graduated implementation plan to ensure these items are implemented on time and in the correct order to support the full AMI roll-out;
- Manage change control processes for software implementations and ensure IT change management processes are adhered to; and
- Work with the Project Lead, Process and Training to ensure FortisBC operational staff are fully trained on the software changes prior to roll-out;

Project Lead, Meter Deployment

The Project Lead, Meter Deployment will be responsible for the following portions of the implementation of AMI at FortisBC:

- Define the implementation plan for meter roll-out in conjunction with the Project Lead – Infrastructure and Hardware and Project Lead, Systems and Integration;
- Manage vendor’s adherence to the pre-defined roll-out schedule;

- Manage costs and issues relating to deployment including the timing of meter purchases and keeping track of installation issues;
- Track vendor SLA and report any variance to the project manager;
- Identify and resolve any metering issues related to the installation or measurement Canada issues;
- Coordinate customer communication related to the deployment and handle escalated customer complaints or issues; and
- Ensure meter exchange data is provided in the format required to the CIS interface for updates to be completed to the customer data on file.

Project Lead, Infrastructure and Hardware

The Project Lead, Infrastructure and Hardware will be responsible for the following portions of the implementation of AMI at FortisBC:

- Manage the design, planning and scheduling of required communication infrastructure and supporting hardware;
- Work with operational groups at FortisBC to ensure they understand new technology and to ensure they are appropriately organized to manage the infrastructure post roll-out;
- Manage approximately $6.8 million in costs related to the installation of infrastructure and hardware;
- Manage the implementation of infrastructure prioritized by meter roll out including all testing and required approvals; and
- Manage the hand-off of infrastructure to operational groups.

Q20.3 Please provide the names and related AMI experience for the AMI consultant and business analyst.

A20.3 The Business Analyst and Consultant required to support the RFP process have not yet been selected. It is expected that these roles would be filled in the event that this application is approved and the project is proceeding. However, the expected skill requirements are as follows:

Business Analyst - Key Skills and Qualifications:

The Business Analyst will be responsible for administrative support during the RFP process. Key skills and qualifications are as follows:

- Strong understanding of FortisBC business processes in all areas of the meter to cash process.
- Experience with document creation and control.
- Exceptional communication skills, both written and verbal.
- At least three years experience in an office environment.

AMI Consultant - Key Skills and Qualifications:

The AMI Consultant is required to provide AMI expertise and vendor support during the RFP process. Key skills and qualifications are as follows:

- Expert knowledge of AMI Technologies including the benefits and challenges of each.
- Familiarity with the major AMI vendors including contacts at each.
- Experience with at least one end to end AMI implementation with more than 50,000 end points.
- Experience writing and managing at least one Request for Proposal “RFP” process.
- An understanding of Measurement Canada regulations as they relate to AMI technologies.

At least three utility references with at least one reference located in Canada.

Q20.4 Why is the Vendor on-site training not part of the AMI procurement?

A20.4 Any training required by FortisBC of the AMI vendor, will be included in the scope of the RFP. It is anticipated that these costs will be $41,000 as per the Application page 33 lines 9-10.

Q20.5 Is Vendor testing, startup and commissioning assistance included in the planned AMI procurement?

A20.5 Yes, the vendor testing, startup and support during deployment are planned to be in scope for the RFP.

21.0 Project Cost

Reference: Exhibit B-1, Section 4.1.1.1 (Meter Reading Savings), p. 13, and Section 5.5 (Employee Impacts), p. 25

Q21.1 The savings shown in this section are related to 2011 dollars and forecasted customer growth. Please provide a version of this table containing actual costs for the existing metering operations for 2007.

A21.1 Please see Table A21.1 below.

Table A21.1: 2007 Metering Operations Cost

	2007 Actual ($000s)
Total Operating Labour	1,477
Total Non-Labour Operating	111
Vehicle Expenses	346
Handheld Support	32
Total Meter Reading Expenses	**1,966**

Q21.2 Does FortisBC anticipate disposing of the vehicles currently associated with the meter-reading function? If so, what is the anticipated value? If

not, what is to be done with the vehicles?

A21.2 Fifteen of the nineteen vehicles are currently leased and will be returned to the lease supplier. The remaining five vehicles are owned and depending upon their condition at the time they are deemed surplus will either enter the company's disposal process or be redeployed so that another vehicle of value can enter the disposal process. Value at the time of disposal is determined by the market and is generally found to be between 10 percent and 20 percent of the original purchase price.

Q21.3 Has FortisBC made any allowance for costs associated with labour-force reduction? Please explain.

A21.3 The Company does not expect to incur any costs associated with the labour force reduction. The respective collective agreement provides for this type of labour force reduction with no expected additional costs to the Company.

22.0 Project Cost

Reference: Exhibit B-1, Section 4.1.1.2 (T&D Operational Savings), pp. 13-14

Q22.1 Measurement Canada requires testing on 16 percent of electronic meters at years 10 and 16. How does this compare with the testing requirements on the current meter population?

A22.1 On average, approximately 2.5 percent of the current non-demand meter population is tested each year.

Q22.2 What is the experience with others who are already using this technology with respect to testing and verification costs? Has this experience been factored into FortisBC's estimates of operational savings and future AMI operating costs?

A22.2 FortisBC is not aware of others' experience with testing and verification costs post AMI implementation. The estimates provided are based on FortisBC's current understanding of Measurement Canada regulation changes which have changed in recent years to account for AMI implementations. Utilities that have implemented prior to these changes would have had different experiences with testing and verification costs.

Q22.3 Will the fact that the entire meter population is to be replaced over a two-year period result in short-term jumps in meter testing costs in ten years and periodically thereafter? If not, why not?

A22.3 Yes, the fact that the entire meter population is to be replaced over a two year period will result in short-term jumps in meter testing costs after year ten. However, these jumps are expected to be offset by the savings of having a greater number of the meter population subject to sample testing. Based on these two factors, FortisBC expects testing and verification costs after year ten to remain at approximately the same level as they are today.

Q22.4 What will be the operational and staffing impacts of having no meters to test for ten years, and how will FortisBC preserve its corporate knowledge of testing processes?

A22.4 Testing and verification of meters is currently done on a contract basis by FortisAlberta, which provides this service to several utilities in Canada. It is anticipated that after the ten year gap, this service would continue to be done on a contract basis. In addition, some sample testing will be required for warranty and risk mitigation purposes within the ten year gap.

Q22.5 Does the ability of a meter to provide real-time feedback on outages depend on the communications technology employed?

A22.5 Yes, the level and type of outage information will be dependent on the specific technology employed. Some technologies rely on a “last gasp” capability where the meter communicates one final transmission to the MDMR as the power is going out. Other systems constantly “ping” or talk to the meters and when a meter doesn’t respond, flags it as an outage.

Q22.6 Please indicate how the $25,000 savings on outage restoration was determined.

A22.6 Cost savings for outage restoration were derived from reducing average call out times due to having knowledge of the areas affected at the outage onset. In addition, the system will identify if any areas are still affected when the power is restored and prevent return call-outs for customers whose power may not have been restored in the original outage response.

23.0 Project Cost

Reference: Exhibit B-1, Section 4.1.1.3 (Customer Service Savings), p. 15

Q23.1 Please explain how each of the cost savings shown in Table 4.1.1.3 was calculated.

A23.1 Following is an explanation of how each of the cost savings shown in Table 4.1.1.3 from the CPCN Application (Exhibit B-1) was calculated:

Reduced Calls Due to Billing Issues:

Based on 2006 figures, there were approximately 0.5 billing related calls per customer and approximately 8.5 FTE were required to answer and resolve these calls (6,300 calls per FTE per year).

The labour cost per FTE including loadings and staff expenses is expected to be approximately $70,500 in 2011. The customer count is forecasted to be 118,500 customers in 2011

Forecasted 2011 billing related calls (without AMI):

118,500 x 0.5 = 59,250

Forecasted 2011 billing related calls (with AMI):

59,250 x 75% = 44,437

Total Reduction: (59,250 – 44,437) calls / 6,300 calls per FTE
= 2.4 FTE

2.4 FTE x $70,500 / FTE
= $169,200

Reduced Billing Errors Requiring Correction:

FortisBC reviewed billing error codes to determine types of errors that would either be reduced or completely eliminated with the implementation of AMI. These error types are detailed in Table A23.1 below.

Table A23.1: Billing Error Types

Error Code	Errors per Customer	Expected Reduction with AMI	2011: Errors Without AMI	2011: Errors With AMI
1. Bill segment has demand	0.00786	100%	931	0
2. Bill segment has no verified end read	0.00305	100%	361	0
3. Cannot auto-cancel	0.00843	100%	998	0
4. Consumptive usage cannot be estimated	0.00010	100%	12	0
5. High usage limit/30 days is greater than allowed	0.02040	75%	2417	604
6. Max consumption increase from last year exceeded.	0.00400	75%	474	118
7. Max consumption decrease from last year exceeded.	0.00300	75%	355	89
8. Meter rolled over more than once;	0.00010	100%	12	0
9. More than 4 estimates in a row. Cannot estimate	0.00420	100%	498	0
10. No previous bill found	0.00430	100%	509	0
11. Not allowed to estimate for this Meter Read Report Code	0.00270	75%	320	80
12. Prev bill has verified end read.	0.03690	100%	4372	0
13. Max consumption decrease from previous bill was exceeded.	0.02210	75%	2618	655
14. Rate does not allow estimate;	0.02140	100%	2535	0
15. USA does not allow estimate;	0.00005	100%	6	0
Total Errors			**16,418**	**1,546**
Error Reduction				**(14,872)**

The average time to resolve each error is 10 minutes.

The cost per hour of a billing agent in 2011 including labour, benefits and associated staff expenses is expected to be $38.89 / hour.

Total Savings ((14,900 errors x 10 min) / 60 min) x $38.89 / hr
= $96,500

Data Entry for Soft Reads:

Based on 2006 figures, there was approximately 0.17 soft reads completed per customer and approximately 0.5 FTE were required to manually enter these readings (34,000 soft reads per FTE).

The labour cost per FTE including loadings and staff expenses is expected to be approximately 70,500 in 2011. The customer count is forecast to be 118,500 in 2011

The soft reading process will be completely eliminated with the implementation of AMI.

Total Savings = (118,500 customers x .17 Soft read / customer) / 34,000 soft reads per FTE
= 0.6 FTE
= 0 .6 x $70,500 / FTE
= $42,300

Q23.2 Will these savings be directly reflected in staff reductions? If not, how will they be realized?

A23.2 These savings may result directly in staff reductions. However, they may also offset future needs for additional FTE’s to support customer growth and existing resource requirements in other areas.

24.0 Project Cost

Reference: Exhibit B-1, Section 4.1.1.4 (AMI Operating Expenses), p. 16

Q24.1 Please explain how the $142,000 for communication costs was calculated.

A24.1 The communication costs relate to satellite costs which were used as the baseline communications technology option. The costs were calculated as follows:

1: $177 / collection device per month for communications costs (ex. Satellite)
x approximately 53 collectors
= $112,572

2: Network management costs $29,500/year

Q24.2 Please explain how the $48,000 for equipment replacements and maintenance was determined.

A24.2 The $48,000 for equipment replacements was determined using a 5 percent annual failure rate on the cost of the communications hardware which was the figure provided by the AMI consultant based on her experience and knowledge of AMI Systems.

Q24.3 What meter failure/replacement rate has been assumed in the cost/benefit calculations? Please estimate the sensitivity of the NPV impact on rates (-0.09 percent from page 4) to that failure rate.

A24.3 During the deployment of AMI, the majority of failures would be identified immediately during the verification portion of the installation process. There would be essentially no costs associated with these failures. For failures occurring after installation, FortisBC has assumed a 2 percent failure rate on the meters within 6 months of installation. The failure rate does not have a significant impact on the financial analysis. For instance, an additional 5 percent over and above the existing 2 percent failure rate would bring the NPV off the Revenue Requirements -0.08 percent from -0.09 percent.

Q24.4 Based on FortisBC's discussions with suppliers and existing users of the technology, what is the failure rate of AMI meters? Has that failure rate been used to estimate ongoing replacement costs?

A24.4 Please refer to the response to BCUC IR No. 1 Q29.2.

25.0 Project Cost

Reference: Exhibit B-1, Section 6.3 (Cost Details), pp. 29-33

Q25.1 Please provide additional detail behind the cost estimates provided in Tables 6.3 and 6.3.2, as well as the costs for project management.

A25.1 FortisBC feels that releasing this level of detail in regards to the cost estimates for the vendor portion of costs would jeopardize the RFP process and prevent the Company from obtaining the most competitive pricing available. However, this information will be provided in confidence to the Commission if requested.

The additional detail behind the internal costs of $2.7 million are detailed in the following tables:

Table A25.1a: IT Infrastructure and Upgrades

System hardware and server	$92,692
Disk space for 10 year reading storage	$35,310
Communication Management System	$51,788
CIS Enhancements	$529,650
Total	**$709,440**

Table A25.1b: Project Management

Project Manager	
Travel Costs	$32,500
Labour plus Benefits	$489,932
Office Supplies / Equipment	$10,000
Leads	
Project Lead Software	
Travel Costs	$8,000
Labour plus Benefits	$320,031
Office Supplies / Equipment	$5,000
Project Lead Install	
Travel Costs	$18,000
Labour plus Benefits	$320,031
Office Supplies / Equipment	$9,000
Project Lead Process & Training	
Travel Costs	$10,000
Labour plus Benefits	$320,031
Office Supplies / Equipment	$5,000
Project Lead Infrastructure	
Travel Costs	$8,000
Labour plus Benefits	$320,031
Office Supplies / Equipment	$15,000
Business Analyst	
Travel Costs	$6,000
Labour plus Benefits	$154,014
Total	**$2,050,570**

Q25.2 For each of these items, please indicate how the work is to be resourced (vendor, contractor, FortisBC in-house resources). For the items that are to be completed by the vendor, does FortisBC expect to have a turnkey contract incorporating these items? Please explain.

A25.2 The portion of capital costs that will be resourced to the vendor versus internal costs can be found in the response to BCUC IR No. 1 Q28.4. Approximately 91 percent of costs will be sourced from the vendor. It is anticipated that the vendor portions will be integrated into one turnkey vendor solution. However, FortisBC may consider individual bids for the installation of meters separate from the technology vendor if practical and cost effective.

26.0 Project Cost

Reference: Exhibit B-1, Section 6.6 (Rate Impact), p. 36

Q26.1 What amount has been established for capital replacements through 2033?

A26.1 There has been no amount forecast for Capital Replacements through 2033 other than those already included in the Application on line 35 of the revenue requirements worksheet (Exhibit B-1).

Q26.2 Please provide a rate impact NPV over ten years.

A26.2 The NPV of the revenue requirements over a ten year term (2008 – 2018) is a net cost of $1.8 million.

Q26.3 For each of these items, please indicate how the work is to be resourced (AMI vendor, contractor, FortisBC in-house resources). For the items that are to be completed by the vendor, does FortisBC expect to have a turnkey contract incorporating these items? Please explain.

A26.3 Please refer to the responses to BCUC IR No. 1 Q28.4 and Q25.2.

27.0 Project Cost

Reference: Exhibit B-1, Section 6.1, p. 28

Project Cost – Assumptions and Data Sources

Q27.1 Please confirm the NPV of revenue requirements is based on a 10% discount rate.

A27.1 Confirmed.

Q27.2 What is the rationale for the 10% discount rate? Please confirm this is a nominal discount rate.

A27.2 The discount rate is based on a real discount rate of 8 percent plus inflation of 2 percent. FortisBC has used a real discount rate of 8 percent as a base case in evaluating its capital expenditures for a number of years. Please also refer to Wait IR No. 1 A22.

Q27.3 Please provide a short rationale for the other assumptions listed in Section 6.l.

A27.3 The rationale for the other assumptions is as follows:

- Internal Labour Escalation – based on the average weekly wage rate increase year over year for the period 2001 – 2006 as reported by BC Stats.
- Inflation for Vehicle Costs – is a composite blended rate for vehicle operating and fuel costs based on the average BC CPI increase for the period 2000 – 2006.
- General Inflation Rate – is the inflation rate historically used by FortisBC in its planning forecasts.
- Composite Depreciation Rate – is the blended depreciation rate weighted by the relative capital expenditure by asset class (meters, network infrastructure, IT infrastructure and upgrades).
- Composite CCA Rate - is the blended CCA rate weighted by the relative capital expenditure by asset class (meters, network infrastructure, IT infrastructure and upgrades).
- Combined Income Tax Rates – are the forecast tax rates as announced by the federal government in the 2007 federal budget.

Internal Labour Escalation: The figure used for internal labour escalation was calculated using BC Stats figures for wage rates in the utility sector from 2001 to 2006. The simple average for this period is 3 percent as shown in Table A27.3a below:

Table A27.3a: Average Weekly Wage Rate

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**Avg**
Average Weekly Wage Rate: Utility Sector ($)	945.5	980.5	1079	998.5	1056	1089	
Increase Year over Year		4%	10%	-7%	6%	3%	**3%**

Inflation for Vehicle Costs: The inflation rate for vehicles was calculated using the average BC Consumer Price Index for Transportation and Motor Gasoline for the periods of 2000 to 2006. These averages were then weighted based on the actual costs incurred in 2006. The resulting inflation rate is 5.0 percent as shown in Table A27.3b below:

Table A27.3b: BC Consumer Price Index

	2000	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**Avg**	**Weighting (from 2006 Actual Costs)**	**Weighted Average**
Transportation (%)	5.4	0.4	3.4	3.2	2.8	4.1	3.4	3.2	71%	2.3%
Motor Gasoline (%)	25.2	0	1	9.4	10.6	12.2	6.9	9.3	29%	2.7%
										5.0%

28.0 Project Cost

Reference: Exhibit B-1, Section 6.2, p. 28-29

Project Cost – Cost Summary

Q28.1 FortisBC indicates it received detailed quotes from two vendors. What was the cost difference between the two quotes? How were the quotes used to estimate the costs of the project (e.g., was one quote selected or was an average used)?

A28.1 As stated in the response to BCUC IR No. 1 Q16.4, the difference in the two quotes was approximately 3 percent. The higher of the two quotes was used to estimate the costs of the Project.

Q28.2 What are the key risks that may affect the final capital costs contained in Table 6.3?

A28.2 Risks to project costs are discussed in the response to BCUC IR No. 1 Q16.7.

Q28.3 Are any of the capital cost estimates subject to fluctuations in exchange rates? If so, what exchange rate was used in the estimates and what is the level of exposure?

A28.3 The vendor portions of the capital cost estimates contained a 1.05 exchange rate US dollars to Canadian dollars. Both vendors indicated that final pricing subject to an RFP process would be provided in Canadian dollars.

Q28.4 What percentage of the capital costs in Table 6-3 would be fixed during the vendor selection process and what percentage would be subject to further escalation during implementation? Please explain.

A28.4 All vendor costs will be fixed during the selection process. Internal costs may be subject to further escalation during implementation. Approximately 91 percent of costs are expected to be within the scope of the RFP process and fixed during the vendor selection process. Please see Table A28.4 below.

Table A28.4: Capital Cost Breakdown

		Total Costs	Vendor Costs	Internal Costs
		($000s)		
i.	Meters and Modules	19,507	19,507	-
ii.	Network Infrastructure	6,700	6,700	-
iii.	IT Infrastructure & Upgrades	1,483	774	709
iv.	Project Management	2,701	651	2,051
	Total Capital Cost	**30,391**	**27,632**	**2,760**
	% Capital Costs		**91%**	**9%**

29.0 Project Cost

Reference: Exhibit B-1, Section 6.3, p. 29

Project Cost – Cost Details

Q29.1 What is the expected life of the AMI system meters? Please provide any support for the expected life estimate, including actual experience, where available.

A29.1 The expected life of the AMI system meters is 25 years. The meters are fundamentally the same as existing electronic meters which typically last beyond 25 years. FortisBC understands that other utilities are using similar ranges at 20 – 30 years expected life.

Q29.2 What is the expected failure rate for AMI system meters compared with conventional meters? Has the failure rate of meters been incorporated in any way in the impact analysis?

A29.2 The expected failure rate during and within six months after the deployment of the AMI system is discussed in BCUC IR No. 1 A24.3.

After this period, the failure rate of AMI system meters is expected to be comparable with conventional meters (within 0.5 percent). This similar anticipated failure rate is due to the fact that the meters are essentially the same, other than the addition of a communications module within the AMI enabled meter. If the communications module is defective, it is most often identified at the time of installation which will prevent the need for a return visit to the premise due to a meter failure. In the cases where the failure happens post-implementation, the AMI infrastructure will allow that failure to be identified early and corrected as soon as possible.

30.0 Project Cost

Reference: Exhibit B-1, Section 6.6, p. 36

Project Cost – Rate Impact

Q30.1 Please confirm the costs and expenses in Table 6.6 are in nominal dollars.

A30.1 The costs and expenses in Table 6.6 from the CPCN Application (Exhibit B-1) are in nominal dollars.

31.0 Project Schedule

Reference: Exhibit No. B-1, 7. Project Schedule, Section No. 7.1, AMI Evaluation Criteria,

pp. 39-41

Q31.1 Will FortisBC be performing a Life-Cycle Cost Analysis ("LLC") as part of the AMI evaluation criteria to determine the lowest cost alternative? If not, why not?

A31.1 Please refer to the response to BCUC IR No. 1 Q6.7.

Q31.2 Would FortisBC consider adding training and testing, startup and commissioning assistance to the AMI evaluation criteria?

A31.2 Training, testing and support during the deployment period will be part of the RFP and therefore part of the AMI evaluation criteria.

Q31.3 If the Commission issues a conditional Order for this Application and after the Contract Negotiations have been completed, would FortisBC consider to re-baseline the project cost and financial data before proceeding?

A31.3 Yes, please refer to the response to BCUC IR No. 1 Q13.2.

Q31.4 Please provide a more in-depth explanation of each optional function in the AMI evaluation criteria and why they are classified as optional.

A31.4 Following is a description of each of the optional items listed in Table 7.1 from the CPCN Application (Exhibit B-1).

Hourly Readings: The AMI system is capable of delivering readings from all meters on the system at hourly scheduled interval rather than strictly daily readings. FortisBC believes that only daily readings are required to support the benefits claimed within the application. Therefore, hourly readings have been listed as optional.

Less than Hourly Interval Readings: The AMI system is capable of delivering readings from all meters on the system at intervals more frequently than once per hour (typically 15 minutes). FortisBC believes that only daily readings are required to support the benefits claimed within the CPCN Application. Therefore, more frequent interval readings have been listed as optional.

Voltage Readings: The AMI system is capable of reporting voltage in addition to consumption readings at the required scheduled intervals. Depending on technology, this voltage measurement can be to varying degrees of accuracy and available for only certain intervals. None of the stated benefits within the application require voltage readings at the meter level. For this reason, it has been classified as optional within the functional requirements.

Tamper Detection: The AMI System indicates tampering with any system component, including meters and communications devices. Depending on the technology, this tamper detection can be related to blink-counts, meter inversion or un-planned outages greater than a defined time period. Most systems flag this tamper detection as an alarm that must be investigated by field staff to determine the validity of the alarm. None of the stated benefits within the application require this type of tamper detection. For this reason, it has been classified as optional within the functional requirements.

Instantaneous Demand Readings: The AMI system is capable of reporting demand in addition to consumption readings at the required scheduled intervals and on-demand as required. None of the stated benefits within the application require demand readings for customers that are not billed demand. For this reason, it has been classified as optional within the functional requirements.

Complex Reporting: The AMI software supporting the AMI system is already equipped with a reporting module that has a number of standard reports and that can be customized based on the utilities needs. If this option is not available from the vendor at a reasonable cost, it is expected that FortisBC can create the required reports from the AMI data using internal tools and resources.

Validation / estimation (VEE) functionality in MDMR: This functionality is to ensure a 100 percent read rate for hourly or 15 minute intervals. If any readings are missed, the MDMR will estimate those using readings before and after the gap. This functionality is only required if the utility will be calculating time-of-use rates buckets with the MDMR rather than at the meter. Since FortisBC intends at this point to support time-of-use rates by utilizing buckets stored within the meter, this functionality is not required.

32.0 Project Schedule

Reference: Exhibit No. B-1, 7. Project Schedule, Section No. 7.2, Project Management, p. 41

Q32.1 Please provide the name and related AMI experience of the Project Manager.

A32.1 Ms. Dawn Mehrer has been assigned as the Project Manager for the AMI project. Ms. Mehrer has been with FortisBC for four years, during which time she has managed the Customer Service Department including the billing, collections and meter reading functions. Ms. Mehrer has also managed a variety of projects including the re-design of the Customer bill, the integration of Princeton Light & Power Co. Ltd. customers into FortisBC's billing system, the repatriation of Customer Service Functions to BC and a Billing System Implementation at Allstream / AT&T Canada.

Ms. Mehrer has been leading the AMI project since its inception at FortisBC and has been working closely with the AMI consultant and vendors in the creation of the CPCN Application.

As the Project Manager, Ms. Mehrer will be expected to manage all aspects of the implementation of Advanced Metering Infrastructure at FortisBC including:

- The RFP and vendor selection process;
- Related system enhancements and software integration;
- Required communications infrastructure;
- Deployment of AMI enabled meters; and
- Ensuring the organizational departments are AMI ready.

33.0 Project Schedule

Reference: Exhibit No. B-1, 7. Project Schedule, Section No. 7.3, Risks and Mitigation, p. 42

Q33.1 Would FortisBC please complete a Consequences/Impacts Criteria matrix as shown below and provide an item qualitative assessment of its relative impact and the likelihood of its occurrence and include the magnitude cost of each item? Probability/Likelihood Criteria is to be provided in table below.

Consequences/Impacts Criteria				
	Given the Risk Is Realized, What Is the Magnitude of the Impact?			
Item	Level	Performance	Schedule	Cost
Batch failures of the AMI meters				
Large Scale failure of the AMI communication infrastructure				
Failure to move data correctly to the CIS Billing System				
Lost AMI readings				
Recruitment of Temporary Resources to read meters				

Probability/Likelihood Criteria (Example)	
Level	**What is the Likelihood the Risk Event Will Happen?**
a	**Remote**
b	**Unlikely**
c	**Likely**
d	**Highly likely**
e	**Near certainty**

A33.1 FortisBC believes that this question is answered in the responses to BCUC IR No. 1 Q16.7 and Q16.8.

Batch failures of the AMI meters	See Q16.8 item (1)
Large Scale failure of the AMI communication infrastructure	See Q16.8 item (4)
Failure to move data correctly to the CIS Billing System	See Q16.8 item (2)
Lost AMI readings	See Q16.8 item (4)
Recruitment of Temporary Resources to read meters	See Q16.8 item (4)

Q33.2 Has FortisBC established any project or post implementation contingency plans and costs? If not, why not?

A33.2 Contingency plans for the major risk factors are listed in Section 7.3 of the CPCN Application (Exhibit B-1). The contingency cost figures can be found in the response to BCUC IR No. 1 Q16.12.

34.0 Project Schedule

Reference: Exhibit B-1, Section 7.3, p. 42

Project Schedule – Risks and Mitigation

FortisBC states meter readers will still be available to manually read meters if required and that temporary resources will be recruited to

manually read meters in the case of a long-term failure.

Q34.1 How long does FortisBC expect to maintain workers to manually read meters after implementation of AMI?

A34.1 FortisBC expects to gradually reduce the number of meter readers during the deployment of AMI with a 100 percent reduction in meter readers once all meters are installed and are confirmed to be transmitting readings to the MDMR.

Q34.2 Are the costs of maintaining manual meter readers included in the impact analysis?

A34.2 FortisBC will not be maintaining any manual meter readers once the AMI system is fully implemented. In the unlikely event of a significant, long-term failure post AMI implementation, temporary or contract resources would be deployed to manually read meters.

Q34.3 What is the risk of long-term failure and what would be the cost of temporary resources to manually read meters in the event of failure?

A34.3 The risk of a long term failure is low. AMI meters typically have room to store several weeks of readings. As long as the communication issue can be restored within that time frame, no reading data would be lost. The cost of temporary resources, if necessary, would depend on the size of the communication issue. If the issue is with one collection device, one part time meter reader would be sufficient in obtaining the readings required for billing. If there were a system wide failure, the cost of the temporary resources would be comparable to the current cost of meter reading at FortisBC.

35.0 Alternatives Considered

Reference: Exhibit B-1, Section 5.7 (Other Jurisdictions), pp. 26-27

Q35.1 Does FortisBC have any information from other jurisdictions regarding variances between initial cost estimates and final (actual) installed costs? If it does, please provide it.

A35.1 FortisBC does not have any information from other jurisdictions regarding variances between initial cost estimates and final costs.

36.0 Alternatives Considered

Reference: Exhibit B-1, Section 8, p. 43

Alternatives Considered

Q36.1 Please describe in detail the status quo alternative assumed by FortisBC.

A36.1 The status quo alternative assumes that meters will continue to be read using the current meter reading process. There will be no cost savings associated with improved processes or technology and the cost of the process will escalate over time due to inflation and customer growth. Required capital upgrades will include a replacement of the handheld meter reading units every five years.

Q36.2 Please provide the base year for the dollar estimates referred to in this section and please provide real dollar equivalents in a common base year.

A36.2 The $1.25 million for upgrading handhelds as outlined in Section 8.0 of the CPCN Application (Exhibit B-1) relate to the upgrades required every five years. The years and dollar amounts can be found in line 16 of the Net Present Value Revenue Requirements analysis in Appendix B (Exhibit B-1).

The operating costs are expected to increase from $2.7 million in 2008 to approximately $3.025 million in 2018 based on 2008 dollars (including customer growth but not inflation).

37.0 Public Consultation

Reference: Exhibit No. B-1, 9. Public Consultation, p. 43

Q37.1 Please explain if FortisBC has informed all customers within its service area. If not, why not?

A37.1 FortisBC customers have been informed through advertisements in the major newspapers as directed by the Commission in Order G-1-08, and is providing additional information to those customers who have requested it as a result. A link to the application was also placed on FortisBC's external website which can be viewed at:

www.fortisbc.com/about_us/regulation/cpcn_applications/ami_project.html.

Since this project is expected to enhance customer service with limited disruption, FortisBC believes that it is unnecessary to broadly provide detailed information at this time. A customer communications program will be initiated once the project is approved and before deployment begins.

Q37.2 What issues were raised by the municipal customers and First Nations within the service territory with regard to the AMI Project?

A37.2 There were no issues or concerns raised by the municipal or First Nations customers within the service territory. Several customers had positive feedback about the reduced need for FortisBC meter readers no longer needing to access customer properties on such a frequent basis.

38.0 Public Consultation

Reference: Exhibit B-1, Section 5.6 (Consultation with Other Utilities in FortisBC Service Territory), p. 26

Q38.1 Has FortisBC approached any of these entities with a view to sharing AMI communications infrastructure and the associated costs? If not, why not?

A38.1 FortisBC has not had detailed discussions with other utilities within the FortisBC service territory regarding the sharing of AMI communications infrastructure and cost.

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

39.0 Other Applications and Approvals

Reference: Exhibit No. B-1, 10. Other Applications and Approvals, p. 43

FortisBC states "Approvals from agencies other than the BC Utilities Commission are not required".

Q39.1 Does FortisBC require Temporary Permission from Verification and Sealing of Electricity Meters (ENF-10), which allows utilities implementing AMI over a shortened timeframe to reduce the number of meters exchanged under existing programs from Measurement Canada? Please explain.

A39.1 Yes. If FortisBC's AMI project is approved and the implementation schedule is finalized, FortisBC will apply to Measurement Canada for dispensation to complete the mass deployment of meters.

40.0 APPENDIX B: Net Present Value Revenue

Reference: Exhibit No. B-1, Appendix B: Net Present Value Revenue Requirements, p. 48

Q40.1 Has FortisBC allowed for replacement cost of AMI and associated equipment, software and hardware in the Revenue Requirements Template?

A40.1 FortisBC has budgeted an incremental $48,000 over and above existing budgets to replace equipment related to the AMI system each year after implementation of AMI. This item can be found on line 35 of the revenue requirements template in the CPCN Application (Exhibit B-1). The budget also includes an annual hardware software maintenance budget of $38,000 per year beginning in year two. This item can be found on line 33 of the Revenue Requirements Analysis in the CPCN Application (Exhibit B-1)

Q40.2 Please explain line 16 in the template. Where is this avoided cost (2x$250,000) shown in the Application?

A40.2 These avoided costs are the avoided Handheld Upgrades on page 23 of the application. There are five replacements that will be avoided (5x$250,000) in years 2013, 2018, 2023, 2028, and 2033 for a total of $1.25 million. For brevity, the template does not show all years in the analysis.

Q40.3 If this entry on line 16 in the template is the Avoided Handheld Upgrades on page 23 of the Application, then these are AMI soft costs and should not be included.

A40.3 FortisBC does not agree. The Revenue Requirements Analysis is intended to show the incremental impact of the Project compared to the status quo (in which the capital expenditure for Handheld Upgrades) would be necessary.

Q40.4 Also the amount claimed on page 23 of the Application is $1.25 million not $500,000 as per line 16 in the template. Please explain.

A40.4 There are five replacements that will be avoided (5x$250,000) in years 2013, 2018, 2023, 2028, 2033 for a total of $1.25 million. For brevity, the template does not show all years in the analysis.

Q40.5 As the Avoided Handheld Upgrades are future avoided costs beyond the completion date of the project, they will need to be added into the LLC table required by the other IR.

A40.5 Please refer to the response to BCUC IR No. 1 Q6.7.

Automated Meter Reading

BUSINESS CASE

2006/2007 Distribution Tariff Application

Table of Contents

FORTIS ALBERTA	**2006/2007 Distribution Tariff Application** **Section 8 – Appendix H** **Automated Meter Reading** **Business Case**

1. Executive Summary

Customers, regulators and customer advocacy groups are asking for the standard for bills to be raised. They are expecting bills that are easy to understand that are based on accurate and current information. Bills that reflect actual consumption, not estimated consumption, in the period being billed are required. When electricity commodity prices are subject to market-driven price fluctuations every month, as proposed in the new Regulated Rate Option ("RRO") Regulation, this will become even more important. Today, as a result of bi-monthly reads, this level of accuracy cannot be met.

Inflationary pressures related to manual meter reading have resulted in significant annual operating cost escalations. FortisAlberta's budgeted costs for meter reads are forecast to escalate further in 2006 and the trend is expected to continue in 2007 and beyond.

To address this problem, FortisAlberta is proposing to fully implement an Automated Meter Reading ("AMR") solution by January 2011. This will be accomplished by investing in capital to offset ongoing operating costs that are subject to inflationary pressures.

The most important benefits realized from AMR will result in reduced operating costs, improved customer service, and future opportunities for long-term benefits to FortisAlberta and its customers.

Operating cost reductions will result from efficient AMR reads, based on conservative estimates, compared to manual read costs increasing over time. Implementation of AMR will result in a positive NPV of $18.8 million in 20 years.

Additional benefits will result in improved customer service as a result of:

- Elimination of estimates;
- Improved data accuracy, retrieval and precision;

- Accurate load settlement; and
- On demand meter reads.

A fully implemented AMR system will result in long-term operational savings, with enhancements to the reliability and operation of the distribution system. AMR will provide the opportunity to:

- Expand the AMR system to include farm customers (REAs);
- Automate Outage Management, including automated notification of a power loss and restoration;
- Efficiently transition to hourly reads, time-of-use reads, or hourly peak demand in support of customer or system demand side management;
- Provide additional information to customers regarding their consumption, allowing them to better manage their electricity use in the future; and
- Perform load profile studies for system planning and rate design, which will result in enhancements to system operation and reliability.

FortisAlberta estimates full implementation of an AMR system will result in a capital investment approaching $90 million, depending on the technology solution selected. For the 2006/2007 Distribution Tariff Application, FortisAlberta is requesting a Phase One capital investment of $8.8 million ($5.5 million for 2006 and $3.3 million for 2007). Phase One will demonstrate the benefits of AMR and the optimal technology solutions for the FortisAlberta service territory. Phase One will allow for analysis of both costs and technology prior to applying to the Alberta Energy and Utilities Board (the "Board") for approval of any future expenditure in 2008.

Benefits are forecast to be minimal for 2006 as infrastructure deployment will not be completed until late 2006. Partial benefits will be realized in 2007 based on the 2006 installations; full benefits will be available in 2011.

The uniqueness of FortisAlberta's operating area, which covers over 240,000 square kilometers, means that the results found in other utility installations, while indicating that there are significant benefits to this technology, are not directly transferable to FortisAlberta's circumstance. FortisAlberta's conservative targeted approach involves installing and testing AMR devices in the FortisAlberta service area. This is proposed for Phase One.

During Phase One, FortisAlberta plans to implement AMR technology on 40,000 sites based on specific geographical regions in the north and south of FortisAlberta's service territory. The areas will be selected based on the following criteria:

- history of issues with the quality of meter reads including current challenges with meter reading;
- varied terrain and types of electrical customers (rural, farm, urban);
- access issues that makes the selected area more expensive to read and meet service standards; and
- opportunities to joint venture with REAs on joint reads.

For the Phase One technology solution, FortisAlberta is planning installation of AMR devices in 100% of sites in a proposed geographical area, supported by two-way power line carrier technology and/or a combination of fixed network radio frequency technology. This will provide experience on how the technology performs in a given region. The attributes of the technology to be measured in Phase One include:

- the ability to cost effectively transition from bi-monthly to monthly meter reads;
- ability to transition to daily, hourly and/or time-of-use reads;
- technology with a proven track record;
- technology that will be supported by the vendor and operate in the field for a period of 20 years;

- support operational efficiencies, which will ensure ease of processing meter read data (read accuracy, read retrieval and read precision);
- population density economics;
- geography (terrain); and
- weather performance;

2. Introduction

AMR implementations are typically driven by government policies or business needs. In the case of the Ontario "Smart Meter" or "AMR" initiative, provincial policy focused on conservation, demand reduction, and time-of-use or time-sensitive rates as the catalysts for full implementation of AMR technology by 2010.

FortisAlberta is proposing AMR implementation to address business needs as a result of the following risks and opportunities:

<u>Risks:</u>

- Inflationary escalation of manual meter read costs;
- Customers' demand for meter data accuracy where bi-monthly estimates are not meeting customer needs and expectations;
- Quality and frequency of meter reads in certain areas of FortisAlberta's vast service territory are subject to significant fluctuations as a result of the labour intensive nature of the manual meter reading process; and
- Off-cycle reads are costly. Certain key financial transactions between parties are currently based on estimated reads and thus not supportive of the competitive retail market design. Notably, move-in and move-out reads are sometimes contested between customers, and retailer switches are made difficult due to the estimates used to transfer sites; and
- Continued inefficient use of Power Line Technicians (PLTs) to perform meter reads, therefore not available to be deployed on system maintenance and capital construction.

Opportunities:

- AMR technologies can support network optimization studies and outage management initiatives, and also reduce system losses (unaccounted for energy) and requirements for field resources;
- The timing of AMR technologies could not be better. Recent regulation changes by Measurement Canada make it very expensive to maintain FortisAlberta's current population of certain electronic and mechanical meters. Approximately 32,000 meters will need to be changed in the next four years. AMR technologies will allow for efficient utilization of the meter fleet to address federal regulatory requirements and mitigate future operating costs. As meters are long-term investments, FortisAlberta must act quickly to address changes to federal regulation; and
- AMR will facilitate safer work practices. Safety is a key priority for FortisAlberta; meter readers drive over 80,000 km in a given year in all weather conditions and can be exposed to hazardous H2S sites and aggressive dogs when obtaining meter reads.

To address these risks and opportunities FortisAlberta proposes to:

- Upgrade existing meters to solid-state meters, subject to statistical sampling;
- Implement Automated Meter Reading technology (AMR); and
- Implement Monthly Meter Reading for AMR-capable sites.

This is a multi-year project, to be phased in on a geographical basis, based on a successful Phase One implementation that demonstrates the project benefits and technology are sufficient to warrant full implementation.

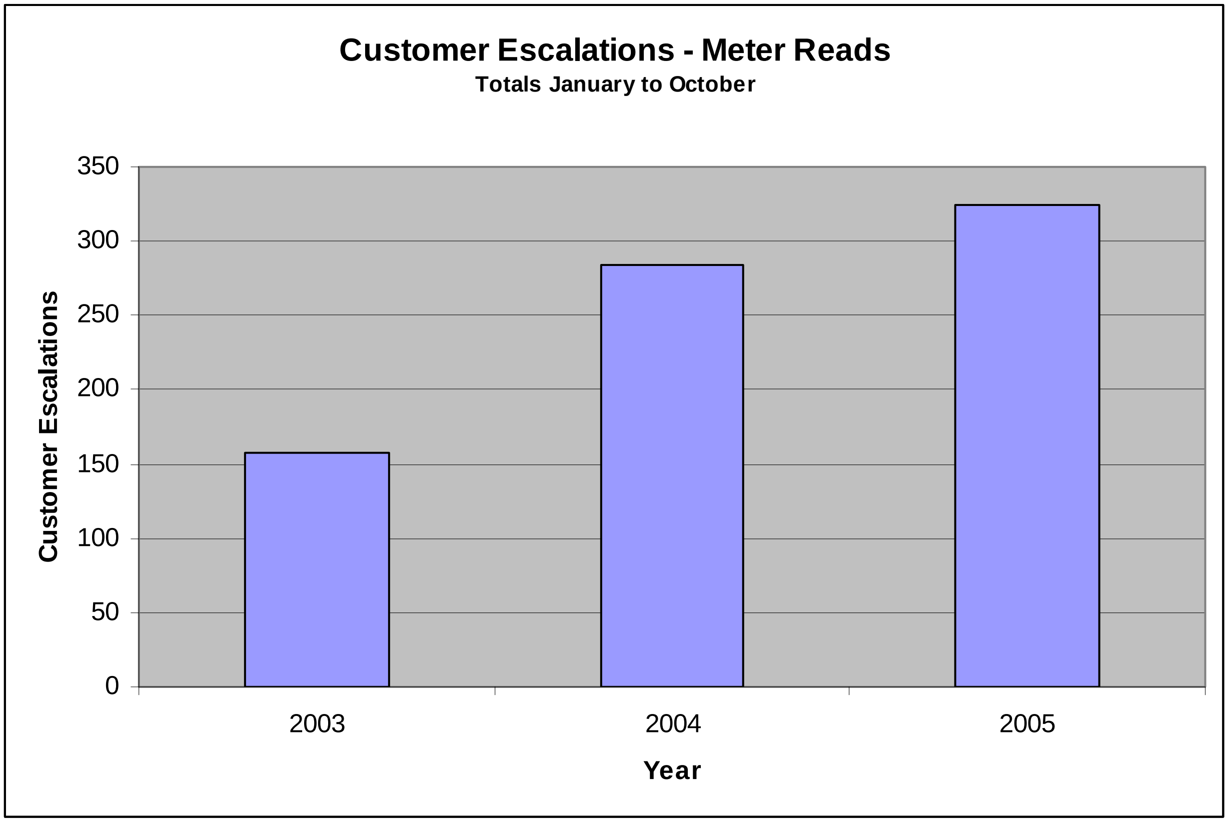
3. Business Drivers

FortisAlberta has an ongoing commitment to reducing costs to customers, while improving customer service. FortisAlberta is expected by customers, regulators and customer advocacy groups to produce increasingly accurate bill information. In 2003, bi-monthly meter reads were implemented to increase the accuracy of billing information. Rates were increased to cover this cost of delivering improved customer information and this has improved FortisAlberta Satisfaction Index (”FSI”) ratings. The proposed AMR solution will increase billing accuracy even further and will reduce costs over the long-term.

3.1 Current Challenges of Reading Meters Manually

Currently, a contract meter reader approaches mechanical meters at the point of delivery on foot and keys a reading from a dial display into a handheld (Itron) unit. Errors can occur as a result of misreading the meter display, a keying error, or the unavailability of a read due to temporary inaccessibility of the meter (for example, inclement weather and aggressive dogs). Most recently, as a result of Alberta’s strong economy, many meter readers have found alternate employment. As a result, a 60% turnover rate has resulted in “skipped” meter read routes. For the first 10 months of 2005, FortisAlberta had 105,000 reads that were originally skipped but were subsequently resent to be read by another meter reader. In many cases, the Meter Reading Vendor was unable to find suitable resources to quickly fill the vacant positions. As a result, customers’ bills may have been unnecessarily estimated at the time of billing.

The manual meter reading process, either by contract meter readers or FortisAlberta field staff, sometimes results in customer complaints such as damaged grass and access issues. Contacts between customers’ pets (usually dogs) and meter readers are growing, where either safety of the pet or the meter reader is at risk. Incremental process improvements are unable to resolve these types of customer complaints since manual reads require access to customer property. AMR would be a step improvement to eliminating this type of customer complaint and would allow 24x7 access to the meter read without requiring access to customer property. Customer escalations related to meter read access are noted below for 2003 through October 2005; 2005 complaints will exceed the escalations received in 2004.



The graph above demonstrates the increasing number of customer escalations resulting from a meter reader or FortisAlberta field staff accessing customer property to complete a meter read.

AMR technology will also allow for remote reads and improve safety as there are a number of hazardous services (sour gas) within FortisAlberta's service territory that requires the meter reader to have specialized training prior to obtaining access. Depending on the technology selected, the reader could either walk or drive in the proximity of the meter to obtain a read, thereby reducing read time, or alternatively need for the reader may be eliminated entirely with the use of telephone, cellular or power line, or other communication networks.

Reading accuracy can be improved by the replacement of the mechanical meter with an electronic meter, which has a digital display and would improve the ease with which the meter can be read. Electronic meters also have higher accuracy tolerances and begin metering earlier in the load curve resulting in a reduction of unaccounted for energy on the distribution system.

FortisAlberta estimates that the upgrade of the residential meter fleet to electronic metering will reduce annual Unaccounted for Energy (UFE) losses by $197,000.

Electronic meters, combined with AMR, will eliminate the need to manually enter a value and any associated errors.

FortisAlberta currently uses telephone technology (digital/analog cell network) for the AMR reads of 1,375 interval sites. This technology is costly; however, it is the most viable alternative for daily interval reads at this time. A replacement of this technology is not within the scope of the AMR business case. These sites are read 5 days per week and capture 15-minute interval data.

Walk by radio frequency technology has been installed to date on approximately 6,000 residential hard-to-read sites. This technology can address most hard-to-read sites, but is subject to interference and still requires a meter reader or vehicle to approach the site. FortisAlberta will continue to install radio frequency AMR technologies in the interim period for hard-to-read sites due to the limited scope of Phase One.

More distant locations are less economical to read on a per-read basis. Irrigation and other rural and isolated customer meters require a significant investment of time, and therefore cost, to read. Significant resources are dispatched annually to obtain 100% of the irrigation site reads to meet customer expectations. Irrigation reads that have electronic meters installed require a Powerline Technician (PLT) read, as the PLT must remove the meter and energize the meter with an inverter to capture the meter read. Reverting back to mechanical meters is not an option as they are no longer manufactured, are subject to shorter seal periods resulting in more frequent meter exchanges.

The most reliable way of obtaining the read is to have the meter transmit information via the power line itself, because it is the least subject to reliance on a third party – whether that be the meter reader or communication technology. By replacing the manual nature of the meter reading process, significant costs savings can be realized in operating expenses. As well, because of reduced driving time, FortisAlberta will reduce fuel costs and vehicle emissions.

In addition to meter read costs, FortisAlberta continues to focus on the quality of the reads. Alberta regulation requires that FortisAlberta attempt to read 100% of the meters bi-monthly (every 65 days) with 98% successfully resulting in validated meter reads. FortisAlberta intends to, with greater consistency, meet or exceed this requirement on a monthly basis with the introduction of AMR technology. As reported in the third quarter of 2005, FortisAlberta is not consistently meeting this requirement even with tremendous efforts expended to read meters on weekends and after hours.

Reporting Period: 3rd Quarter of 2005

Standard, per Settlement System Code, Appendix B 4.5(a): Equal to or greater than 98%

Month	% Cumulative Meters Read
July 2005	98.7%
August 2005	96.0%
September 2005	94.8%
Quarterly Average	**96.5%**

In order to support the Tariff Bill Code and the Regulated Default Supply regulation, there is only a small window of time where a meter can be read. FortisAlberta is trying to ensure that meters are read within a 4-day window. However, as the reads are sent out on average every 60 to 61 days, any challenge – inclement weather, a reader's vehicle breaking down, meter reader leaving employment without notice – would result in the 4-day read window not being met. FortisAlberta has worked hard to meet this challenge with the Meter Reading Vendor by having resources flown-in from other provinces, re-deployed from other areas and working overtime and weekends to catch-up. Although reads are achieved, they may be late and the solution is not sustainable given that moving resources from area to area is difficult in FortisAlberta's vast territory (over 240,000 square kilometers).

As reads are received at the office, the read is compared to historical figures and exception reports are produced. The exceptions are either easily addressed (such as a meter reader reversing digits) or require a re-read. A work order for the re-read, known as a Billing Inquiry (BI), is requested of a contract meter reader or FortisAlberta field staff. Previous studies have shown that FortisAlberta field staff will typically deal with 20,000 to 27,500 Billing Inquiries that require a site visit every year. A re-read request can take eight days to process. Improvements are continually investigated; however, AMR will allow for a step improvement, eliminating a substantial portion of these types of Billing Inquiries. It is estimated that the cost of Operations resources dispatched to perform these reads exceeds $586,000 annually.

3.2 Growing Recognition of AMR Benefits

Not only are internal and customer needs leading to this proposal, but changes in FortisAlberta's operating environment also support the implementation of this technology. FortisAlberta currently provides bi-monthly meter reads based on a manual read system.

The successful implementation in Alberta of 175,000+ electric AMR meters and 157,000+ gas AMR meters by ATCO have proven the importance placed on the quality and cost associated with reads. This was a multi-year project to install two-way, power line carrier communication technology. Positive customer opinion has been realized through a decrease in estimates, accurate bills and fewer meter reading staff. Customers in the ATCO service territory benefit from monthly meter reads as a result of implementation of the AMR technology.

Other regulated jurisdictions in Canada, such as Ontario, are moving to implement AMR technology on all sites by the end of 2010. This is driven by the provincial government to address demand side management, conservation and time-sensitive rates. Ontario accounts for 5 million of the 12 million residential meters installed in Canada, thus by 2010, 42% of residential meters in Canada will be electronic AMR-capable. Once the AMR infrastructure is in place in Ontario, all residential and small general service customers with less than 50 kW demand will benefit from hourly and/or time-of-use meter reads.

Others in the United States have implemented AMR for water, gas and electric. Some recent examples of these are Puget Sound Electric & Gas, PG&E, PP&L and Duquesne Light.

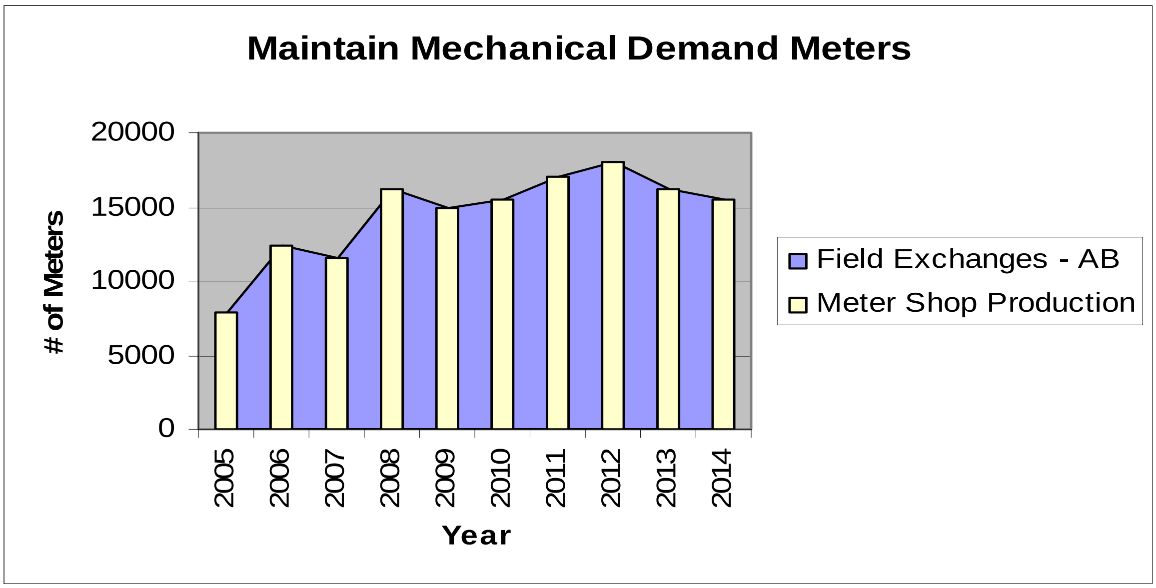
3.3 Changes to National policy (E-26 and SS-04)

Recent legislation proposed by Measurement Canada will result in increased frequency of meter exchanges. Approximately 32,000 mechanical demand meters are currently used in

FortisAlberta's operating area. The proposed regulation will require that 100% of these mechanical meters be exchanged every four years. By replacing the meters with the solid-state electronic meter, 7% of the meters will need to be sampled after 10 years and then again after another 6 years. The implication is that mechanical meters will require four 100% exchanges in the time that the electronic meters will require two sample exchanges. Thus, the opportunity to leverage this initiative with AMR technology must be acted on immediately to maximize the upgrade to the meter fleet.

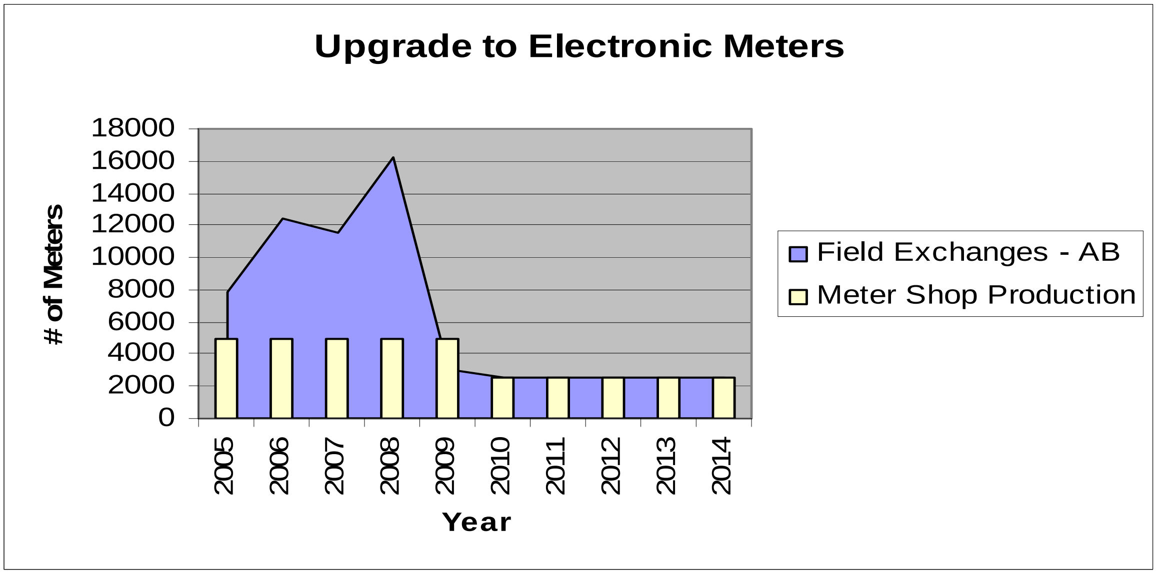
The two graphs below depict the impact of doing nothing or upgrading to electronic meters. Field exchanges impact PLT resources; meter shop production impacts Meter Services resources, representing the number of meters to be exchanged and tested.

Do nothing, maintain existing mechanical demand meters



The graph above demonstrates the impact of maintaining a meter fleet that is not optimized for statistical sampling. The area represents the number of field exchanges that will be required by PLTs; the bars represent the number of meters that must be bench-tested by the Meter Shop. As a result of federal regulation, the allowable seal extensions of meters have been reduced from 6 years to 4 years, resulting in an increase in the number of meters that require exchange annually.

Upgrade, mechanical demand meters with AMR electronic meters

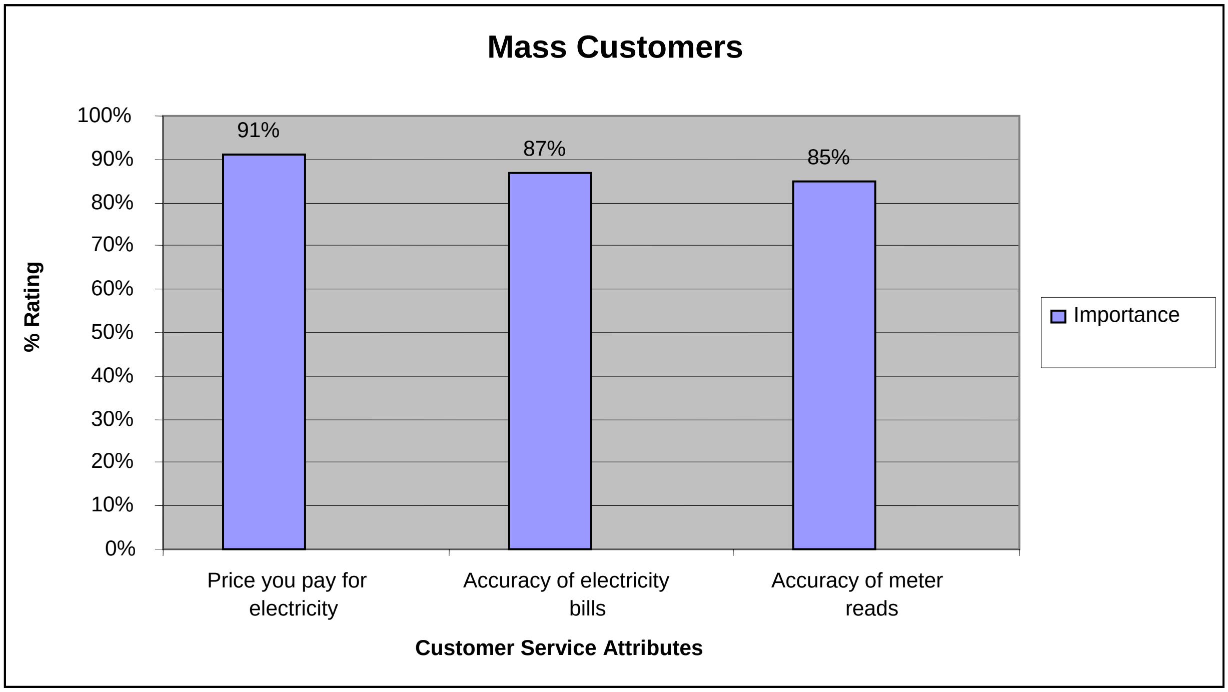


The graph above demonstrates the impact of optimizing the meter fleet for statistical sampling. The number of field exchanges required by PLTs until 2009 does not change, as a result of the process to remove 32,000 mechanical meters through the annual meter exchange program. All meters removed from service in 2006 and future years will be replaced with electronic meters subject to statistical sampling. This will allow for a dramatic reduction in the required PLT resources beginning in 2009. The requirement for Meter Shop resources drops off in 2005 as the removed meters are retired, and therefore do not require re-verification. New meters purchased for the exchange are electronic meters that are statistically sampled at the time of purchase, subject to fewer resources.

Accurate meter reads are essential. Upgrading the current mechanical metering equipment to electronic solid-state meters will improve the accuracy of meter reads, reduce the cost of reading meters, and significantly reduce the number of field exchanges required by PLTs.

3.4 Monthly Meter Reads

Monthly Meter Reads are essential to improving accuracy of electricity bills. It is clear that FortisAlberta customers are not satisfied with estimates and as indicated in the Q3-2005 customer survey, they continue to rank accuracy of meter reads and accuracy of bills as the most important attributes, with over 85% and 87% of the surveyed customers ranking their importance as “9” or “10” out of “10”.



A sample of customer comments from FortisAlberta’s Q3-2005 customer survey reveal that the issue is related to the “estimate” that is generated by the system:

- "because they don't always read our meters. We like our bills to be exact"
- "they bill every month but they don't read the meter ever month. Never current to our bill"
- "readings are not taken, they are estimated and they are way out of line"
- "cause I've had trouble on the estimates lately and I'm not happy with that and their estimates are way out and I then I get credits and I don't like credits”
- "do not like estimated billing like old system where you read the meter and paid for the power you actually used"

- "they are not using the meter reading they are just estimating on the bill"
- "The date that my power was read and I thought that it was read every month but it wasn't so I ended up getting a humongous bill"
- "accuracy of billing could be improved. Accuracy of meter reading needed"
- "estimate for 2 months but each month we are paying monthly for our meter reading but we get estimates"
- "problem with overestimation..."
- "the billing, they use estimates you can't look at your meter and compare it to your bill because it is estimated and they don't come all the time and read it"

Customers do not understand billing based on estimates. At least 5% of FortisAlberta customers have seasonal consumption patterns that vary from month to month. Billing estimates are based on previous consumption which can be dramatically different than actual consumption for a period. This creates confusion and leads to customer complaints about inaccurate meter reads.

FortisAlberta continues to look at system enhancements to improve estimates; however, the customer would still be billed on an estimate. This does not account for fluctuations in actual usage from one month to the next. Customer survey results clearly indicate that mass customers dislike their bills being based on estimates. Consumption estimates are expected to be of particular concern to customers with implementation of the proposed RRO regulation, which may result in electricity prices fluctuating on a monthly basis in 2006.

Implementing monthly meter reads (current practice is bi-monthly reads) is a way to mitigate customer dissatisfaction. AMR technology will allow for a quick and efficient transition to monthly reads. To meet the requirement for monthly reads in the absence of AMR technology, FortisAlberta could Cancel, then Rebill all sites previously estimated once actual manual reads have been received in order to "straightline" the estimate between actual reads. Even with the "straight-lining" of consumption, customers could still dispute that this new estimate does not really represent their consumption in the period. Also, this would require performing cancellations and rebilling transactions on approximately 200,000 accounts per month. Impact to systems and business processes for FortisAlberta and Retailers are not acceptable, as transaction volumes would double and would only legitimize the practice of adjusting a bill after it has been sent to a customer.

Transitioning from bi-monthly reads to monthly reads with the current manual read system would double meter reading operating costs, assuming resources could be found. However, with an implemented AMR infrastructure, FortisAlberta would have the ability to transition from bi-monthly to monthly meter reads without doubling meter reading operating expenses. Costs to transition are considered minimal and have the ability to reduce the overall cost per read, as the cost of reads obtained through the AMR system would be significantly lower than manual reads.

Daily meter reads would result in additional costs due to the volume of data to be managed and stored and is not considered practical other than for load profile studies or for irrigation customers that frequently switch service on and off.

3.5 Regulatory Drivers

FortisAlberta reads the majority of its meters every second month. There is a risk of regulatory non-compliance whenever an actual read is missed, whether due to environmental (e.g. inclement weather) or operational (e.g. equipment, routing) issues.

The relevant regulations that govern our decision to reduce risk are:

- The Billing Accuracy Regulation requires that estimates must be within 20% of the average daily consumption (as evidenced by actual meter readings). Each incident of non-compliance imposes a penalty on the Distribution Company.
- The Settlement System Code (SSC) requires that all cumulative meters must be read within any 2-month period, and DCMs (settlement-ready data) must be available for a minimum of 98% of them.

The Tariff Billing Code, introduced in July 1, 2005, also supports the need for more frequent meter reads in an automated fashion. Some examples include:

- The Retailer for regulated customers now invoices the commodity portion of their customers invoices based on FortisAlberta estimates, whereas previously only the D&T portion or less than 1/3 of the bill amount was impacted by these estimates. The regulated Retailer must do so to align commodity and distribution charges. An estimate generated now has a greater impact on customers' bills than in the past;
- The requirement for daily tariff bill files has reduced the time frame in which FortisAlberta is able to validate and improve upon meter reads and also system-generated estimates; and
- The requirement to provide an estimate if a read is not received by the published billing date of the site results in a loss of flexibility for FortisAlberta to re-send for manual verification of reads.

Recent contemplated changes to the RRO Regulation will lead to significantly larger number of rate changes than contemplated in the past.

- This becomes a greater issue when monthly RRT flow-through pricing is implemented (RDS July 1, 2006). The price of energy could significantly change from one month to another.
- A greater period of time between actual reads will reduce the accuracy of the allocation of consumption across the period of rate change. The result is undesirable for either the customer (if the estimate was higher than actual consumption might have been) or the service provider (if the estimate was lower).
- A greater number of actual reads will improve the quality of data used for load settlement and billing purposes.

3.6 Operational Efficiencies

Operational efficiencies expected include:

- Reduction of billing queries or disputes from customers and Retailers when billing is based on actual reads;
- Reduction in manual re-estimations and cancellation/rebilling of previous estimates when actual reads are received. Internal processes for managing too many estimates in a row will also be reduced;
- Reductions in off-cycle meter read requests when actual reads are missed. These "special" meter read requests to dispatch a meter reader, FortisAlberta PLT or field customer service person to read a meter are costly and inefficient when compared to reads conducted as part of a scheduled route. Off-cycle reads result from customer complaints, inaccurate estimates, and skipped reads. Each off-cycle read requires a trip to the customer's property;
- Reduction of customer calls to the Contact Center for FortisAlberta and Retailers; and
- Improved monitoring of meter performance, such as stopped or failing meters, which would result in reduced meter compliance failures and improved meter seal extension.

3.7 Unmetered Oilfield

Currently FortisAlberta is undergoing an audit on all of the unmetered oilfield services. This audit covers approximately 10,000 sites and will take place during 2005 and 2006. In the following years, FortisAlberta will continue to audit unless it can gather enough supporting information to warrant metering these services. The audit is checking for a variety of things including broken seals, added horsepower, additional equipment, changes in equipment, increases or decreases in load, and idle/active status changes. From the sample audit completed in 2004 on 377 sites, the average broken seal rate was 64%. In 2005, FortisAlberta has already seen a broken seal rate of 75% and an overall increase in load. Broken seals are an indication that the horsepower rating of the motor has been adjusted without prior authorization from FortisAlberta.

One use of AMR would be to determine the load profile of unmetered sites with the ability to poll daily usage data for a period of time at selected sites compared to the current profile of a site that is metered, based on bi-monthly reads. It is important to determine the impact of unmetered oilfield sites with the use of load profiles to ensure that non-oilfield customers and Retailers are not cross-subsidizing such sites.

3.8 Load Settlement

AMR and consistent actual monthly meter reads, rather than estimates, will allow for ongoing process enhancements resulting in accurate load settlement. AMR is expected to improve load settlement by:

- Reducing the amount of estimated consumption at Initial Monthly Settlement. Currently 95% of consumption on irrigation sites and 65% for residential, farm and cumulative-metered general sites is estimated.
- Reducing the variability between Initial and Interim Settlements, resulting in less variability of load allocation (and energy costs) to the Retailers. The replacement of estimated consumption with actual consumption will reduce the swings between Initial and Interim settlements between rate classes.
- Improving Irrigation load allocation. During irrigation months, the variability in Unaccounted for Energy (UFE) from Initial to Interim settlement can be mainly attributed to the estimated under-allocation of Irrigation consumption;
- Reducing Pre-Final Error Correction (PFEC) and Post-Final Adjustment Mechanism (PFAM) requests as a result of fewer meter read errors;
- Reducing Daily Cumulative Meter (DCM) errors with fewer manual touch points of meter reads; and

- Providing a tool to analyze the accuracy of existing Load Settlement profiles and revise these profiles for more accurate allocation of load to the specific rate classes, if required or desired.

4. Financial Analysis / Assumptions Used

Analysis of historical and current data to determine the full details required for a business case for a widespread implementation would be performed during Phase One. As such, cost savings over the 2006/2007 period, for Phase One, will not be immediately realized until economies of a full scale implementation are in place.

Benefits are forecasted to be minimal for 2006 as infrastructure deployment will not be completed until late 2006. Partial benefits will be realized in 2007 based on the 2006 installations.

4.1 Project Costs

For the 2006-2007 Distribution Tariff Application, FortisAlberta is requesting a Phase One capital investment of $8.8 million ($5.5 million for 2006 and $3.3 million for 2007). Phase One will demonstrate forecast benefits are achievable and identify the technology solutions that are optimum for the FortisAlberta service territory. Phase One will allow for analysis of both costs and technology prior to applying to the Board for approval of further phases for 2008 and beyond.

FortisAlberta estimates full implementation of an AMR system will result in a capital investment approaching $90 million depending on the technology solution selected.

Cost Assumptions, Phase One and Full Implementation ($000)

Alternative: AMR (Total capital expenditure for installation of AMR)										
	Cost Assumptions			Phase One	Phase One	Phase Two	Phase Three	Phase Four	Total 2006 to 2010
Description	Unit	No. of Units	Unit Cost 2005$	2006	2007	2008	2009	2010	Total
Capital Expenditures:		2006 2007 2008+							
Meters	Meter	25,665 14,200 120,074	0.179	4,691	2,657	23,011	23,563	24,128	78,050
IT	Estimate		75	78	81	84	88	91	422
Project Manager	Estimate		135	140	146	152	158	164	760
Analyst	Estimate		105	109	114	118	123	128	591
Engineering and Supervision	E&S	9.60% 9.92% 10.00%		482	297	2,336	2,393	2,451	7,960
Total Capital Expenditures				5,500	3,296	25,701	26,324	26,963	87,784

Costs in the table above identify the total capital expenditures for Phase One (2006 and 2007) and the total cost of full implementation for the period of 2006 to 2010. A significant portion of the $8.8 million Phase One cost will be directly attributable to the purchase and installation of electronic meters, communication infrastructure and IT infrastructure. A Project Manager, Analyst, and IT specialist are required to support the installation and analyze the cost and benefits associated with the technology choice.

4.2 Project Benefits

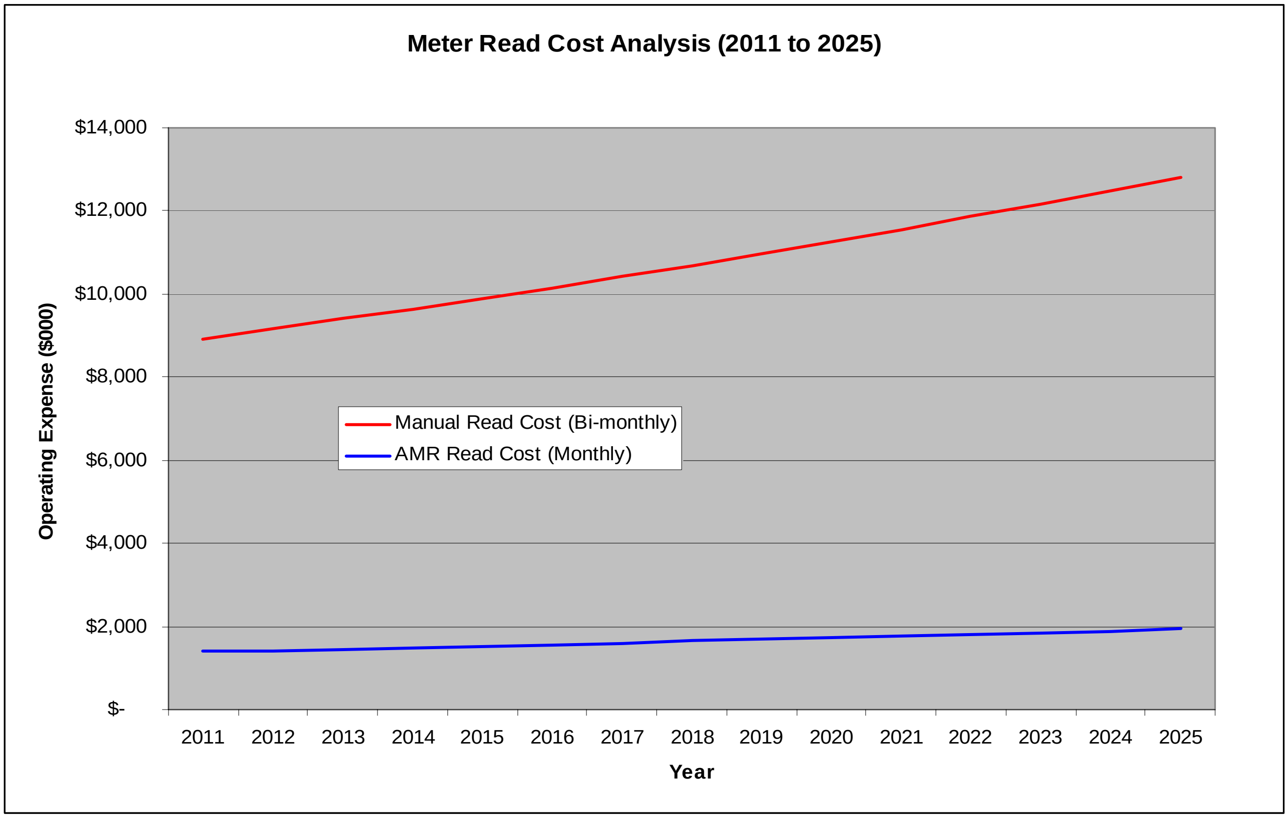
The project benefits are identified by year in the following table. Full descriptions of the project benefits are included in section 5 of this business case.

AMR Benefits – Operating Cost Savings after 20 years ($000)

Alternative: Business as Usual (Costs to continue to operate a manual meter reading system)									
	Cost Assumptions			Phase One	Phase One	Phase Two	Phase Three	Phase Four	Total
Description	Unit	No. of Units	Unit Cost 2005$	2006	2007	2008	2009	2010	2006 to 2025
Operating Expense									
Meter Reading Cost	Estimate		6,230	0	326	2,223	4,553	6,994	141,588
Special Meter Readings	Estimate		86	0	5	32	67	105	2,398
Billing Inquiries and Implausible - Administrative	Estimate		200	0	11	75	156	243	5,552
Billing Inquiries - Network Operation	Estimate		586	0	32	220	457	713	16,271
Power Diversion / Line Losses	Estimate		380	0	20	136	278	427	8,636
Meter Accuracy Loss	Estimate		197	0	10	70	144	222	4,486
Mechanical Meter Replacement	Estimate		1,803	0	0	0	0	0	45,678
Total Operating Expense				0	403	2,756	5,656	8,703	224,609
Total Cost				**0**	**403**	**2,756**	**5,656**	**8,703**	**224,609**

Costs in the table above identify the total operating benefits for Phase One (2006 and 2007) and the total operating benefits for the period of 2006 to 2025. The operating benefits provide a financial analysis to compare the alternatives of Status Quo (Bi-monthly manual meter read) and AMR. Operating benefits are estimated to be minimal for 2006 as infrastructure deployment will not be completed until late 2006. Partial benefits will be realized in 2007 based on the 2006 installations; full benefits will be available in 2011. Following a description of the benefits identified in the table.

- Meter Reading Cost – Reduction of contract meter reading costs;
- Special Meter Reading – Reduction in off-cycle reads and check reads by contract meter readers;
- Billing Inquiries and implausible (Administration) - Reduction in administration costs due to reduced billing inquiries and implausible;
- Billing Inquiries (Network Operations) – Reduction in Billing Inquiries performed on site by PLTs and field customer service staff;
- Power Diversion / Line Loss – Reduction in losses due to theft and / or stopped meters;
- Meter Accuracy Loss – Reduction in line loss due to aging mechanical meters that slow down over time and do not register at lower starting currents; and
- Mechanical Meter Replacement – Reduction in the number of meter exchanges required annually with the upgrade of mechanical demand meters to electronic demand meters subject to sampling.



The graph above illustrates the operating benefits of transitioning from the Status Quo (Bi-monthly, manual meter read) to the alternative of a monthly AMR read. The comparison is based on full implementation of an AMR system by 2011. In 2011, it is estimated the impact of inflation will result in annual manual meter read expenses approaching $9 million, compared to AMR operating expenses estimated at $1.4 million

4.3 Evaluation of Alternatives

A full explanation of the alternatives can be found in section 6 of the Business Case**.** The financial model identifies the incremental Net Present Value, 20 years after full implementation is a positive $18.8 million.

Automated Meter Reading Comparative Analysis

Incremental Net Present Value - 2006 to 2025 ($000)

Total capital expenditure for installation of AMR and operating costs to operate the AMR system

Alternative: AMR									
									Total
Description	2006	2007	2008	2009	2010	2011	2012	2013	2006 to 2025
Cost									
Capital Expenditures	(5,500)	(3,296)	(25,701)	(26,324)	(26,963)	0	0	0	(87,784)
Operating Expense	0	(113)	(467)	(903)	(1,358)	(1,391)	(1,424)	(1,459)	(27,603)
Total Cost	(5,500)	(3,408)	(26,169)	(27,227)	(28,321)	(1,391)	(1,424)	(1,459)	(115,387)
Quantified Benefits									
Cash Inflow	0	0	0	0	0	0	0	0	0
Total Quantified Benefits	0	0	0	0	0	0	0	0	0
Net Cash Flow	(5,500)	(3,408)	(26,169)	(27,227)	(28,321)	(1,391)	(1,424)	(1,459)	(115,387)

Costs to continue to operate a manual meter reading system

Alternative: Business as Usual									
									Total
Description	2006	2007	2008	2009	2010	2011	2012	2013	2006 to 2025
Cost									
Capital Expenditures	0	0	0	0	0	0	0	0	0
Operating Expense	0	403	2,756	5,656	8,703	11,211	11,534	11,867	224,609
Total Cost	0	403	2,756	5,656	8,703	11,211	11,534	11,867	224,609
Quantified Benefits									
Cash Inflow	0	0	0	0	0	0	0	0	0
Total Quantified Benefits	0	0	0	0	0	0	0	0	0
Net Cash Flow	0	403	2,756	5,656	8,703	11,211	11,534	11,867	224,609

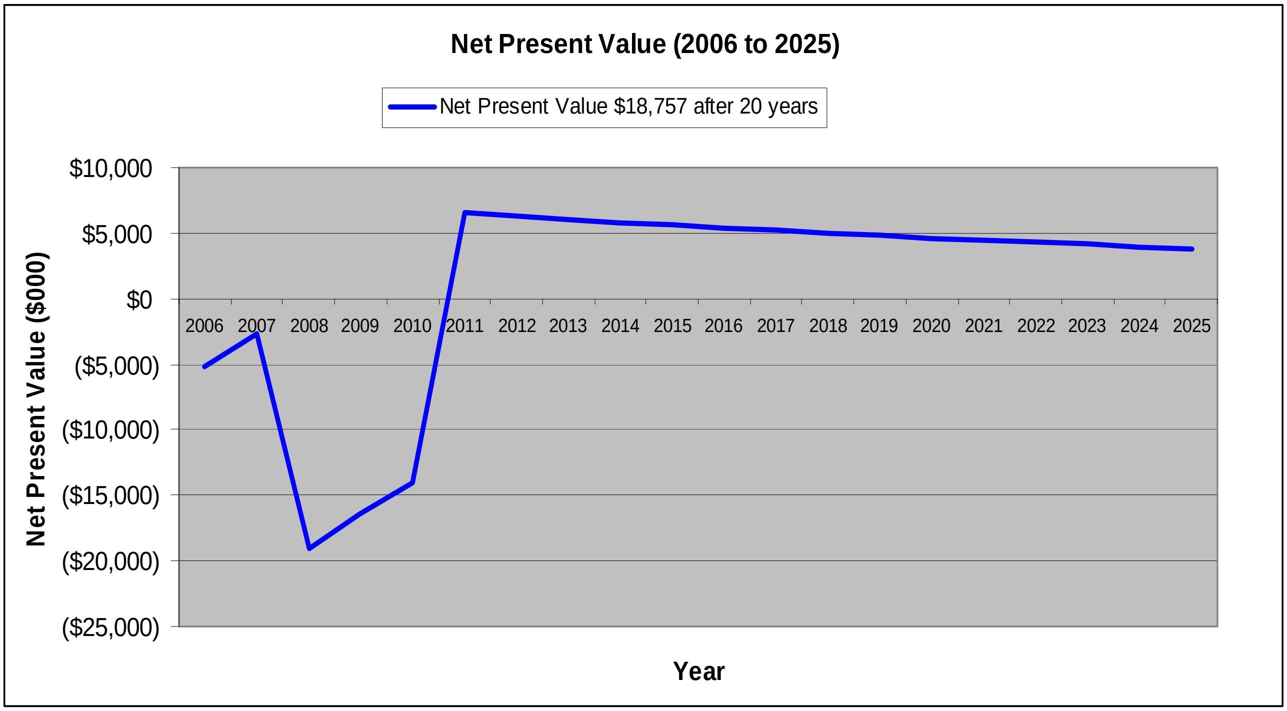
Net cash flow required for installation of the AMR system and future net cash flow savings as a result of the AMR system

Incremental Cash Flow									
									Total
Description	2006	2007	2008	2009	2010	2011	2012	2013	2006 to 2025
Cost									
Capital Expenditures	(5,500)	(3,296)	(25,701)	(26,324)	(26,963)	0	0	0	(87,784)
Operating Expense	0	290	2,289	4,753	7,345	9,820	10,109	10,408	197,006
Total Cost	(5,500)	(3,005)	(23,412)	(21,571)	(19,618)	9,820	10,109	10,408	109,221
Quantified Benefits									
Cash Inflow	0	0	0	0	0	0	0	0	0
Total Quantified Benefits	0	0	0	0	0	0	0	0	0
Net Cash Flow	(5,500)	(3,005)	(23,412)	(21,571)	(19,618)	9,820	10,109	10,408	109,221
Incremental Net Present Value									
									Total
Description	2006	2007	2008	2009	2010	2011	2012	2013	2006 to 2025
Discount Rate	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	
Net Present Value	(5,140)	(2,625)	(19,112)	(16,457)	(13,987)	6,543	6,296	6,058	18,757

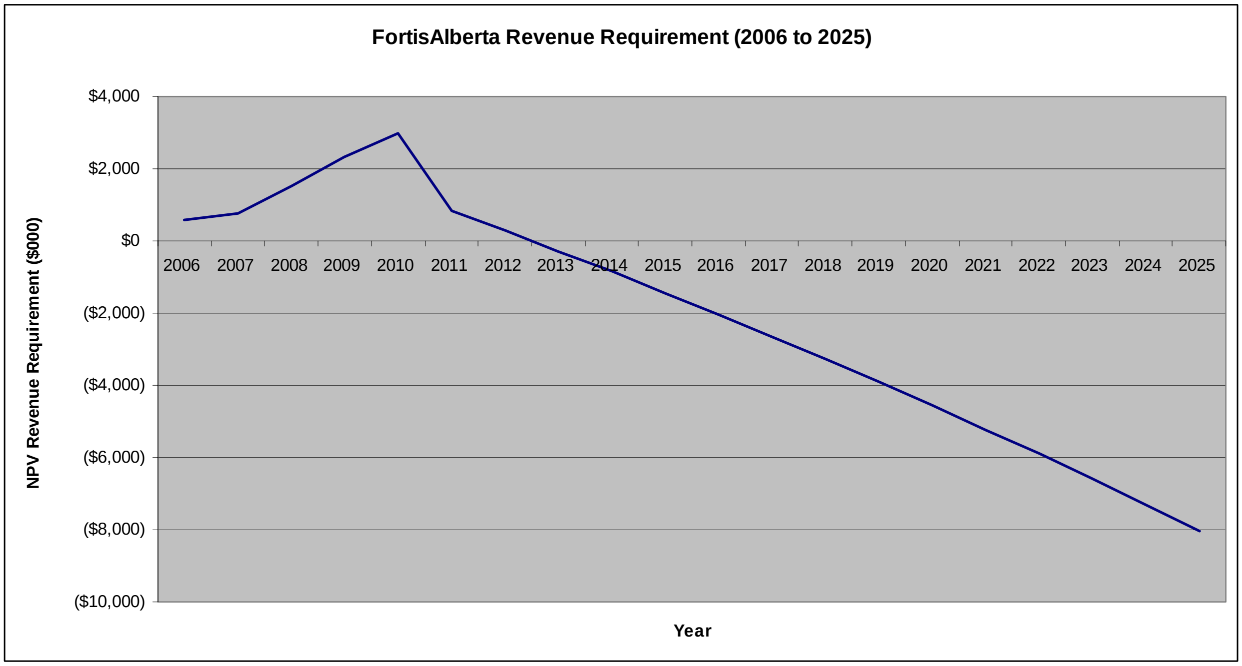
The table above includes a comparative financial analysis of two alternatives: Status Quo (Business as Usual) and Automated Meter Reading. Automated Meter Reading identifies the forecasted capital expenditures and operating costs to provide monthly meter reads; the Status

Quo alternative includes comparable operating and capital costs of the existing bi-monthly manual meter reading process.

The costs presented in this analysis are incremental and include only those capital and operating costs that would differ between the two alternatives over the twenty year analysis period. Internal expenses were estimated by FortisAlberta; external costs were provided by external service providers.



The graph above identifies that after full implementation in 2011 of the AMR system, the annual NPV becomes positive once full benefits are realized. The total NPV is estimated to be $18.8 million after 20 years.



The graph above identifies that the FortisAlberta revenue requirement results in a rate impact to customers during the period 2006 to 2012. Once full benefits are realized in 2013 the customer will benefit from an on-going reduction in the revenue requirement for FortisAlberta.

4.4 Assumptions

- Costs are based on a fully implemented two-way communication network;
- Only savings specifically related to operating savings have been included and are conservative;
- Additional opportunities after full implementation have not been included as cost savings at this time;
- Cost savings for Phase One will lag the financial benefits of full implementation and will be prorated during the analysis of Phase One;
- Informational costs were received from vendors of cellular, telephone, radio frequency, and power line communications; and
- All technologies have approximately the same installation costs.

5. Business Benefits

In support of corporate and departmental priorities, FortisAlberta proposes to take advantage of the following benefits of an AMR technology:

Business Benefits of Automated Meter Reading	Reduction Operating Costs	Improved Customer Service	Future Opportunities (2011)
Reduce meter reading costs: • Efficiently transition to monthly reads • Eliminate inflationary pressure (long term labour costs) • Eliminate resource pressure, contract meter readers not required • Reduction of off-cycle meter reading costs	√	√	
Reduce meter fleet maintenance costs; • Upgrade meter fleet to electronic meters, subject to statistical sampling	√		
Improve operations; • Improve meter data (accuracy, retrieval, precision) • Eliminate estimates • Improve customer service (on demand reads) • Reduce power theft / customer tampering • Reduce environmental impacts (eliminate manual reads) • Accurate load settlement • Accurate load profiles (customer load profiling)	√	√	
New Regulated Rate Option (“RRO”) • Address monthly variable energy pricing (June 30, 2010)			√
REA Meter Reads; • Expandability to farm customers • Shared costs	√	√	√
Outage Management; • Notification of loss of power • Notification of restoration of power			√
Infrastructure in place to transition to; • Hourly reads • Time-of-use reads • Hourly peak demand			√

A more detailed explanation of the many benefits of AMR technology listed in the table above are as follows:

1. Reduce contract meter reading costs:
   - Phase out manual meter reading from 2006 to 2010;
   - Eliminate manual meter reading post-2010; and
   - Eliminate reliance on contracted meter reads.
2. Efficiently transition to monthly reads:
   - Bill off actual meter reads in an accurate and timely manner;
   - Eliminate reliance on estimates;
   - Maintain a strong and verifiable audit trail that is understood by customers, Retailers and internal stakeholders;
   - Increase compliance;
   - Improve accuracy of meter read data means that Retailers' energy procurement costs will be more aligned with actual requirements;
   - Improve customer satisfaction because invoices will be more accurate;
   - Reduce the number of estimates required for Load Settlement, resulting in more accurate data provided to market. Less variance between initial, interim and final settlement results;
   - Provide more equitable prorating of consumption data over rate changes (energy or D&T);
   - Improve economies of scale with meter reading;
   - Reduce implausible estimates and the related corrections;
   - Reduce the number of cancel/rebills processed;
   - Reduce customer queries; and

- Improve Retailers' bill accuracy and ability to collect from end-use customers.

3. Eliminate inflationary and resource pressure due to increasing fuel prices and difficulties current contractor has retaining qualified staff:

    - Budgeted costs per read are estimated to escalate substantially by 2007, compared to 2005;
    - High staff turnover, impacted by strong economic activity in Alberta and aging population;
    - Unpredictable performance due to resource issues, which do not allow for consistent achievement of 98% validated meter reads;
    - Fuel surcharges increasing operating costs;
    - Currently, contractor regularly flies meter readers in from Ontario to complete meter reads, for compliance reasons; and
    - Rising labour costs, labour shortages and aging work force, if not addressed, will further hamper customer service and meter reading accuracy. This currently is one of the major challenges for our Meter Reading Vendor.

4. Reduce costs associated with special reads that normally result from safety, access and weather issues:

    - Currently PLTs or field customer service staff complete special reads (approximately 20,000 annually) for sites that contract meter readers can not access;
    - Access issues are more prevalent due to H2S (oilfield), increased security (Telus), and cross-contamination (chicken/pig farms); and
    - Significantly reduce or eliminate additional re-read labour costs due to extreme weather (snow, flooding) resulting in road closures and access to remote locations

5. Reduce re-verification costs and meter exchanges by upgrading electronic meters with AMR functionality. (Federal regulation pursuant to the Electricity & Gas Inspections Act, specifically E-26 and SS-04):
    - Address changes to national policy as a result of reduced seal periods, from 6 to 4 years;
    - Address changes to both existing and proposed national policy that favors the sampling of electronic meters over mechanical meters; and
    - New federal sample plans indicate increased failures of mechanical meter population from the current 6%, approaching 15% or higher, annually. Pending final federal consultations during 2006.

6. Improve meter data accuracy:
    - Address irrigation reads, allow for daily reads on irrigation sites eliminating non-compliance in achieving reads, or having PLT complete reads;
    - Improved read accuracy and elimination of estimates, majority of customer complaints stem from the estimating process; and
    - Mitigate the risk of non-compliance issues, due to not achieving required reads on time (September 2005 – potentially, only 93% reads achieved, with considerable effort working throughout a weekend, 98.9% achieved).

7. Improve customer service:
    - On demand reads from central station, no site visit will be required to address customer complaint or billing inquiries;
    - Ability to offer management services to customers such as usage information, interval data, profiling, and/or WEB access to meter reads as a service or a fee per service;
    - Time-of-use or interval metering or demand response availability;
    - Call center staff provide on-demand or near on-demand read while customer is on the phone. Currently it may take 5 days to resolve billing inquiries;

- Currently FortisAlberta estimates for Move-in/Move-outs, Retailer Switches, rate breaks; however, customer surveys indicate that customers dislike having their bills based on estimates. (Q3 – 2005, Accuracy of electricity bills continues to be the most important attribute for customers, closely behind "Price" at 87%.);
- Reduction of complaints from FortisAlberta service territory, fewer calls to the call center with improved read accuracy, elimination of estimates, and elimination of site visits by PLTs or meter readers; and
- Reduced punitive measures, fines for incorrect billing as were imposed upon Aquila Networks Canada in the past. The Billing Accuracy Regulation required that estimates must be within 20% of the average daily consumption. Each incident of non-compliance resulted in a $75 penalty to the Distribution or Retail Company.

8. Reduce power theft / customer tampering:

- According to CEA studies, 0.25% of revenue is lost due to theft or $380K annually for FortisAlberta;
- AMR system allows near real-time identification of removed, inverted, tampered or stopped meters, which can not be readily identified by a manual meter read;
- Allows for immediate investigation of a site, currently FortisAlberta may have 2 to 3 months of lost revenue before it may, if at all, be aware of a tamper situation;
- Due to field resource limitations, there are currently no activities taking place to proactively address or monitor theft of service. AMR technology would allow for remote monitoring of all customer installations;
- Energy theft and tampering of the service continues to escalate creating unsafe situations for staff; and
- Two-way communication at sites would allow for remote disconnects and monitoring of tampered sites.

9. Reduce environmental impacts:

   - Provide load profile and system net load monitoring;
   - Reduce vehicle and fuel costs to perform off-cycle reads (over 20,000 site visits per year by FortisAlberta field staff);
   - Reduce vehicle and fuel costs to perform actual meter reads (over 2,400,000 site visits per year by meter readers); and
   - Promote conservation and demand side management with move to time-of-use or demand-sensitive rates.

10. Support more accurate load settlement:

    - Reduce the estimated consumption at Initial Monthly Settlement;
    - Reduce the variability between Initial and Interim Settlements, resulting in less variability of load allocation (and energy costs) to Retailers;
    - Improve Irrigation load allocation;
    - Reduce PFEC and PFAM requests as a result of fewer meter reader errors;
    - Reduce DCM errors with fewer manual touch points of meter reads; and
    - Provide a tool to analyze the accuracy of existing Load Settlement.

11. After June 30, 2010, all customers will be subject to the new Regulated Rate Option ("RRO") and monthly variable energy pricing. As a result:

    - More customer switches between Retailers, therefore it will be critical to have more actual reads;
    - Retailers will likely seek options to differentiate between themselves. One way to do that is to offer peak and off-peak pricing. With current metering technologies, this is not available; and
    - Smaller customers want more options to control their pricing.

12. Perform Load Profiles:
    - Allow for the profile of sites for a set period of time to determine system maintenance, capacity and upgrades; and
    - Profile of unmetered and metered sites, such as unmetered oilfield sites to collect profile data to warrant system changes

13. REA Meter Reads: Opportunities will be available to cost share or provide meter reading services to REAs that share common feeders. FortisAlberta has been advised by REAs that they are interested in jointly working with FortisAlberta to implement and share costs of Power Line Communication-based AMR systems for their customers.

6. Alternatives

6.1 Alternatives to AMR

Alternatives such as status quo or going back to internally provided meter readers have been considered and discarded for the following reasons:

- Status Quo – this alternative fails to meet meter data accuracy expectations of FortisAlberta customers, does it take advantage of opportunities for operations optimization, efficient utilization of the meter fleet nor address the inflationary impacts on manual meter reads. Step changes are required to address customer satisfaction related to accuracy of meter reading and accuracy of electricity bills, specifically the elimination of estimations before 2010 and the new RRO, which is a 100% variable energy price.

- Moving from contract readers to internally provided readers – Currently, there is no evidence available to demonstrate internal readers are more cost-effective than outsourcing the meter reading function to an external vendor. It is further uncertain how changing from pay-per-read methodology used to compensate meter reads to hourly salary for internal readers would impact operating costs. Ultimately, replacing an existing external workforce with an internal workforce does not address inflationary escalations and the current economic environment leading to labour shortages and the aging workforce is expected to worsen.

6.2 Technical solutions and alternatives within AMR

There are two technical alternatives for FortisAlberta's technology choices related to the implementation of AMR. They include:

1) Radio Frequency
2) Power Line Carrier

Presentations by AMR vendors were made to a team representing Meter Services, Meter Data Acquisition, the Meter Shop, Finance, Information Technology, and Regulatory on February 9 and 10, 2004. The team assessed the products and companies for their ability to improve read accuracy, reduce reads, and increase the overall value proposition to FortisAlberta's customers. The following is a summary of the presentations:

1) Hunt Technologies

   Using "turtle" technology, a customizable packet of information is conveyed to a central point (the substation) through the power line. The read does not rely on an individual, eliminating risk exposure as a result of misread or weather/driving condition. Metering information is stored in the at-site unit and the substation unit for 30 days, further ensuring security of data. The substation unit can be contacted via cellular telephone, land line or fiber at any time to pick up information, which will be no greater than 23 hours old, and would typically be scheduled to be called daily. Thus, estimated bills would be eliminated. Communication is continuous, so as soon as a signal is lost (no greater than 20 minutes) alert messages are sent to the administration office to notify of a power failure and indicate which units are affected, isolating the affected area. Once power supply is re-established, the alert system notifies that units are operating again (within 35 minutes), ensuring that all customers have had power re-established or to determine if isolated customers are still affected. This will feed nicely into FortisAlberta's outage management system, replacing the need to wait for customer calls. Additionally, alerts are sent when a meter has been tampered, and consumption is tracked separately if the meter is inverted.

With this technology reads can be downloaded daily or monthly. With complete implementation of Power Line Communication ("PLC") technology, meter reading costs are expected to be reduced to two staff to administer incoming data. Implausible Meter Reads and Billing Inquiries are eliminated.

2) Distribution Control Systems Inc. (DCSI)

Another power line carrier technology, Two-Way Automatic Communication Systems (TWACS), is similar to the above, but uses a different technology so information is available on a "poll and response" basis, with the benefit that the individual meters can be called at any time to get a current read. However, all information is available on a call-in basis only, as there is no automatic communication. This AMR has the ability to flag power outages. Analysis of these flags can lead to identification of meter tampering. As an outage management tool, this system still requires a customer call to trigger an analysis. This technology has the option of flexibility to provide interval reads. This is the technology that ATCO has installed.

3) Itron / Schlumberger

Radio frequency based technology will reduce the cost of reads by saving meter reading time. Accuracy increases to approximately 98% in appropriate applications. Radio handhelds reduce read time by needing only to approach the meter, not walk right up to the meter, and keying errors are eliminated. For further time savings, a more powerful (less portable) unit can be installed to pick up readings at a slightly greater distance, enabling a meter reader to drive by, rather than walk by. This will speed up the collection process and reduce the cost of reads in dense installations. Monthly meter readings would be required, offsetting the savings of reduced manpower from route time reduction.

The accuracy of this technology and the 5-day turnaround to get a re-read meant that this was not the preferable technology.

During July 2005, Itron amended its original offer to include a combination fixed network radio frequency solution for areas with urban population density and a power line carrier solution for rural areas with low population density. The power line carrier solution is a new partnership with Cannon Technologies. The combination fixed network and power line carrier option is a common communication platform that monitors the constant transmission of meter reads to collector points. Collector points are then downloaded to the central station. This option is not a true two-way communication technology for fixed network sites, however collectors are upgradeable to transmit information to remote disconnect devices or load control units. In urban locations, this option allows for a gradual implementation for upgrade from walk-by to drive-by to fixed network and would allow us to continue to use the 6,000+ radio frequency meters currently installed, with the addition of collector technology at key points, with no upgrades required at the meter.

7. Recommendation

In the 2006-2007 Distribution Tariff Application, FortisAlberta is planning Phase One implementation, resulting in a capital investment of $8.8 million ($5.5 million for 2006 and $3.3 million for 2007) to ensure the forecasted cost benefits are achievable and the technology solutions are optimum for the FortisAlberta service territory.

Should Phase One be successful, FortisAlberta estimates full implementation of an AMR system will result in a capital investment approaching $90 million depending on the technology solution selected.

For a Phase One technology solution, FortisAlberta is recommending an installation to 100% of sites in a geographical area, with two-way, power line carrier technology and/or combination fixed network Radio Frequency technology.

This will provide certainty with respect to how the technology performs in a region, which is unique for important attributes including:

- the ability of the technology to cost effectively transition from bi-monthly to monthly meter reads;
- ability in the future to transition to daily, hourly and/or time of use reads;
- technology that has a proven track record;
- technology that will be supported by the vendor and operate in the field for a period of 20 years;
- support operational efficiencies that allow for the ease of processing meter read data (read accuracy, read retrieval and read precision)
- population density economics;
- geography (terrain); and
- weather performance.

FortisAlberta plans to implement AMR technology on 40,000 sites based on specific geographical regions within FortisAlberta's service territory. In Phase One, FortisAlberta will measure the impact on each attribute listed above.

Savings are forecasted to be minimal for 2006 as infrastructure deployment will not be completed until late 2006. Partial benefits will be realized in 2007 based on the 2006 installations.

The uniqueness of FortisAlberta's operating area, which covers over 240,000 square kilometers, means that the results found in other utility installations, while indicating that there are significant benefits to this technology, are not directly transferable to FortisAlberta's circumstance. As a result, a conservative targeted approach, which involves installing and testing AMR devices in the FortisAlberta service area, is proposed for Phase One.

8. Plan of Action

Due to the length of time since the last Request for Information ("RFI") (2003/2004) and the recent amendment from Itron (July 2005), a new RFI would be initiated to reassess costs and technology.

Key Dates	Key Milestones
Dec 2005	Project team formed
Jan 2006	RFI sent to vendors
Feb 2006	Vendor responses
Mar 2006	Select vendor presentations
April 2006	Project award
Q3-Q4 2006	Installation (26,000 points)
Q1-Q2 2007	Installation (14,000 points)
Q3-Q4 2007	Project Learnings Analysis
2007 to 2010	Subsequent business cases and installations performed annually by geographic region.

9. Phase One Controls

- Develop key performance indicators and measurements to ensure accurate analysis of performance;
- Assign internal project team to manage installation and analysis of data to support full implementation;
- Hire independent consultant, independent of meter or AMR communication vendor, to assist with the development and award of Phase One;
- Contract installation to vendor or secondary provider;

- Perform field audits of installation by secondary provider;
- Require that Vendor host Head End data collection servers and software, reducing IT risk, consider hosting servers late 2007;
- Ensure that meters allow for manual read or conversion to alternate AMR communication technology; and
- Perform full analysis of actual installation costs and actual savings.

If FortisAlberta's analysis of Phase One determines that it is prudent to proceed, FortisAlberta will recommend moving forward with full implementation and will apply to the Board, in future tariff applications, for approval of later phases, to be phased in on a geographical basis.

FORTIS ALBERTA

Advanced Metering Infrastructure (AMI)
Phase II – Full Deployment Business Case

2008/2009 Phase I Tariff Application

Table of Contents

1. Executive Summary

FortisAlberta currently faces a number of challenges in the management of its meter data, including, meeting customer expectations regarding the accuracy of their bills, overcoming meter reading issues involved with reading over two million customer sites annually, many of which are rural, managing the escalating costs of manual meter reading and responding to evolving regulatory requirements and market conditions. Advanced Metering Infrastructure ("AMI") technology presents an alternative to addressing these customer service and operational issues while simultaneously introducing the opportunity to significantly reduce operating cost associated with manual meter reading. The benefits of this alternative are confirmed through widespread deployment of AMI throughout North America. The maturity of the core meter reading technology and the diversity of functional features are now available at a cost that supports mass scale deployments. The affordability of AMI technology and its ability to address the challenges identified above have created an environment where moving to monthly, or more frequent meter reads, and the elimination of estimated bills will benefit all FortisAlberta customers.

To test the viability of AMI technology, FortisAlberta received approval to proceed with Phase I of an AMI project as part of its 2006/2007 Negotiated Settlement Agreement. FortisAlberta issued a Request For Proposals ("RFP") process in 2006, selected a reliable and experienced AMI vendor, Hunt Technologies LLC ("Hunt"), and implemented the selected technology in a representative number of sites in varied geographic areas, terrains, and rate classes across FortisAlberta's service territory. The purpose of Phase I was to determine whether AMI technology could be deployed in FortisAlberta's primarily rural and semi-urban service area in support of billing accuracy and at a cost that would justify full-scale replacement of conventional meters with AMI-enabled meters. Phase I implementation results have confirmed that the selected Power Line Carrier ("PLC") AMI technology deployed by Hunt will meet these key objectives.

Based on the success of Phase I, FortisAlberta is proposing full deployment of the PLC AMI technology, with a capital investment of approximately $104.3 million over 2008-2010.

Specifically, for this tariff application period, AMI capital costs are forecast as $23.5 million in 2008, $57.0 million in 2009 and $23.8 million in 2010. Investment in the AMI technology will displace $9.7 million of capital expenditures that would have otherwise been incurred through continued use of conventional meters and current meter reading practices. After factoring out the displaced capital expenditures, the overall incremental capital cost of the AMI project over the 20-year average life of the meters is $94.6 million.

To support full-scale deployment, the Net Present Value ("NPV") of the quantifiable benefits over 20 years was required to match or exceed the proposed capital expenditures. Even with the exclusion of intangible benefits to customers of accurate monthly bills, the payback period for a full deployment of the AMI technology, compared to monthly manual meter reading costs, is 8 years with an NPV of $93.7 million in 20 years. When compared to the current practice of bi-monthly manual meter reading, the payback is forecast to be 12 years with an NPV of $10.8 million in 20 years. Upon full deployment, the cost of a single bi-monthly meter read is expected to drop from $2.50 per read to a fixed monthly charge of $0.20 per site for any combination of scheduled, off-cycle or customer requested reads. The annual meter reading operating costs are expected to be less than 1% of FortisAlberta's overall operating expense. This is a significant drop compared to current bi-monthly manual meter reading costs, which today represent approximately 7% of FortisAlberta's operating expense.

The forecast reduction in revenue requirements over the test period was calculated as the difference between full AMI deployment and monthly manual meter reading.

2008-2009 Revenue Requirements ($000)

Description	2008 Forecast	2009 Forecast
Incremental Revenue Requirement	$(5,484)	$(183)
Total Revenue Requirement	$260,500	$290,100
Incremental (reduction) as % of Total Revenue Requirement	(2.11%)	(0.06%)

A negative revenue requirement demonstrates that implementing accurate monthly customer bills through AMI over three years is more cost-effective than introducing monthly manual meter reading.

The diverse benefits associated with a fully provisioned AMI system extend far beyond improvements in billing accuracy and the replacement of manual meter reading. For both customers and retailers this includes increased accuracy of outage information, quicker outage response and restoration, and more timely and detailed customer energy usage information. Additional operational benefits include more efficient distribution system planning, voltage monitoring, rate profiling, and the ability to implement remote disconnect and reconnect functionality. The AMI system selected by FortisAlberta addresses both the immediate needs of FortisAlberta's customers, retailers and other electricity market participants and offers flexibility to evolve with changing requirements.

Throughout the implementation of Phase I, FortisAlberta has consulted extensively with customers, retailers and customer advocacy groups regarding the AMI technology and its performance in Phase I. Feedback received from these stakeholders has been very positive, with their issues being predominantly related to prudent improvements in billing standards as well as making electricity bills easier to understand and representative of actual monthly consumption. As the AMI technology allows for substantive long-term customer benefits and enables the advancement of the Alberta retail market by systematically replacing estimated reads with accurate meter data, this initiative has received widespread support from FortisAlberta stakeholders.

In summary, FortisAlberta has demonstrated in Phase I that PLC AMI technology, provided by Hunt has proven itself to be beneficial to customers by demonstrating that it will have a positive NPV over the life of the AMI System when compared to manual bi-monthly or monthly manual reads; deliver timely and accurate monthly or more frequent meter reads; and provide additional functionality both immediately and in the future for the benefit of FortisAlberta customers.

2. Introduction

This business case is part of FortisAlberta's 2008-2009 Distribution Tariff Application and sets out the forecast costs and benefits of the AMI Phase II Deployment. Phase I of the AMI project was a functional test of the AMI technology and was approved in the Alberta Energy and Utilities Board Decision 2006-063 as part of FortisAlberta's 2006/2007 Negotiated Settlement Agreement ("NSA").

Recognizing that implementation of AMI throughout FortisAlberta's service territory would involve significant expenditures, the Automated Meter Reading Phase I Protocol (Appendix C; Decision 2006-063) was established with the Customer Intervener Groups ("CIG'") as part of the NSA. It was understood and agreed that the information shared at the scheduled meetings on Phase I was without prejudice to the future position of all parties. The protocol was used by FortisAlberta to share information related to the project, including selection of technology, implementation in target areas and testing, and determination of costs and benefits. FortisAlberta met with CIG on two occasions (Jan. 1, 2007 and May 15, 2007) to comply with the protocol.

Further details of FortisAlberta's AMI Phase I implementation is provided in Attachment R-1.

2.1 Background

The benefits of monthly meter reading are well recognized. The Alberta Government's *"Report of the Task Force on Electricity Billing Issues"* (2002) recommended that "investor and municipally owned Wire Service Providers ('WSPs') should commit to read meters on a bi-monthly or – if economically feasible – monthly cycle".

Until the introduction of AMI technology, the economics could not support a move to monthly meter reading. AMI technology for meter reading purposes has matured significantly over the last 10 years. There are about 72 million AMR endpoints currently serving utilities. Industry predictions are this number will grow to 86 million by the end of 2007.[1] System-wide utility implementations began in 1994 with Kansas City Power and Light. More recently, the Province

[1] Source: AMRA January 2007 Newsletter "Metering Industry Matures and Strengthens".

of Ontario has undertaken to deploy 0.8 million AMI meters by the end of 2007 and in excess of 4.5 million meters by the end of 2010 under the Smart Meter Implementation Plan. Pacific Gas and Electric is in the process of deploying 9.1 million electric and gas meters within the same time frame. Enel (Italy) has completed the world's largest AMI implementation with the installation of 30 million meters in 2005. AMI technology is already well established in Alberta with over 180,000 sites installed by ATCO Electric.

3. Project Description

This Phase II Full Deployment Project proposes to upgrade all existing meters to solid-state meters and implement the AMI system throughout FortisAlberta's service territory over a three-year period. As conventional meters are exchanged for AMI-enabled meters, FortisAlberta proposes to implement monthly meter reading for AMI-enabled sites.

3.1 Project Objectives

FortisAlberta's primary objective of Phase II is to capture the following benefits for customers:

- Increase customer satisfaction through billing accuracy;
- Meet or exceed Settlement System Code cumulative meter data collection standards; and
- Reduce operating costs.

3.2 Project Scope and Schedule

Phase II of the AMI implementation is forecast to require the installation of approximately 405,000 AMI units. The scope includes the following:

- *Prioritization of geographic areas for deployment.* Deployments will be prioritized based on geographic location of the existing installations, customer and retailer impact, meter reading requirements and joint venture third-party opportunities with interested REAs, while minimizing operating costs. As an example, higher cost manual read locations and areas experiencing higher meter reader turnover will be converted first.

- *Substation hardware upgrades.* There will be an installation of meter data collection equipment at 158 substations in 2008 to 2010.
- *AMI-enabled meter installations.* FortisAlberta will deploy approximately 63,000 meters scheduled to begin in August of 2008, followed by 239,000 meters in 2009, and 103,000 meters in 2010.
- *Management of the transition from the current outsourced meter reading vendor.* FortisAlberta re-negotiated the contract to support a seamless transition from manual meter reading to AMI-enabled meters. The contractual provisions include mechanisms for the meter vendor to flow through their costs to FortisAlberta and provide one-time incentive payments to meter readers to ensure they are retained until their areas are fully transitioned.

This business case does not include nor preclude future justifications for metering unmetered oilfield sites or replacing existing interval meters.

3.3 Incremental Capital Costs

The AMI Phase II Deployment forecast capital expenditures and offsets are provided in Table 3.3 followed by an explanation of each line item. Forecast capital offsets are calculated as the difference between full AMI deployment and the Monthly Manual Meter Reading alternative described in section 6.1.

Table 3.3 2008 - 2010 Forecast Capital Expenditures and Offsets
AMI Phase II Deployment

Description	Forecast 2008 ($000)	Forecast 2009 ($000)	Forecast 2010 ($000)	Total ($000)
Capital Expenditures				
AMI Phase II Meters	$6,993	$32,720	$14,661	$54,374
Meters 2007 Growth (for period January – December 2007 only)	1,578	279	0	1,857
Substation Hardware	4,041	4,262	1,107	9,410
Installation Costs	10,341	17,240	6,425	34,006
Subtotal Capital Expenditures	$22,953	$54,501	$22,193	$99,647
Capital Offsets				
Retrofit Meters	$(1,231)	$(1,449)	$0	(2,680)
Subtotal Capital Offsets	$(1,231)	$(1,449)	$0	$(2,680)
Net Capital Expenditures	**$21,722**	**$53,052**	**$22,193**	**$96,967**
Engineering and Supervision	1,737	3,979	1,665	7,381
Total Capital Expenditures	**$23,459**	**$57,031**	**$23,858**	**$104,348**

(Totals may vary due to rounding.)

Table 3.3A Description of Capital Expenditures and Offsets
AMI Phase II Deployment

Line Item	Description
AMI Phase II Meters	Number of sites as of Dec. 31, 2006 remaining to have AMI installed (excludes Phase I implementations).
Meters 2007 Growth (for period January – December 2007 only)	Anticipated number of sites deployed during 2007. Future growth requirements for meters will be purchased through regular operations.
Substation Hardware	Physical hardware costs for installations of meter read collection equipment at the substation.
Installation Costs	Project and installation services. Labour provided by the AMI vendor, FortisAlberta and other contractors.
Retrofit Meters	Current meter purchases can be retrofitted later to accommodate an AMI module.

3.4 Incremental Operating Expense

The AMI Phase II Deployment forecast operating costs and offsets over the 2008-2009 test period are provided in Table 3.4 followed by an explanation of each line item. Forecast operating offsets are calculated as the difference between full AMI deployment and Monthly Manual Meter Reading.

Table 3.4 2008 - 2010 Forecast Operating Expense and Offsets
AMI Phase II Deployment

Description	Forecast 2008 ($000)	Forecast 2009 ($000)
Operating Expense		
External meter reading and system operating costs	$6,934	$5,487
Telecom	121	412
Subtotal Operating Expense	$7,055	$5,899
Operating Cost Offsets		
Conventional meter compliance testing	$(47)	$(49)
Field removal costs for conventional meter compliance testing	(96)	(101)
Contract Labour for meter reading validation	0	(112)
Field Service - billing inquiries	(21)	(96)
Subtotal Operating Offsets	$(164)	$(358)
Total Operating Expense	**$6,891**	**$5,541**

(Totals may vary due to rounding.)

Table 3.4A Description of Operating Expense and Offsets
AMI Phase II Deployment

Line Item	Description
External meter reading and system operating costs	Operating expenses for scheduled manual meter reading and vendor system operating costs for AMI meter reads. Manual meter reading costs have been included until project completion in 2010.
Telecom	Telecommunication costs related to modems to communicate between the collectors and FortisAlberta office systems.
Conventional meter compliance testing	Meter services cost reductions related to decreased testing on conventional meters due to Measurement Canada dispensation (see Section 4.3 for details).
Field removal costs for conventional meter compliance testing	Field services cost reductions related to decreased field exchange costs on conventional meters due to Measurement Canada dispensation.

Contract Labour for meter reading validation	Contract labour reductions due to decreased validation of manual meter reads.
Field Service - billing inquiries	Internal labour reductions due to decreased field inquiries to verify meter readings.

4. Business Drivers

With a service territory of 240,000 square kilometers, FortisAlberta faces many challenges in obtaining bi-monthly manual meter reading, including site access, safety of employees and contractors, meter reader turnover, and escalating cost of meter reading all of which directly affect the level of service provided to FortisAlberta's customers and stakeholders. Specific business and technical drivers of the proposed AMI Phase II Deployment are provided below.

4.1 Customer Satisfaction

In the FortisAlberta Customer Satisfaction Survey prepared by Environics, the Q4-2006 results indicated that customers ranked "accuracy of electricity bills", "accuracy of meter readings" and "price you pay for electricity" as the three most important customer satisfaction attributes. In this same survey, the percentage of customers that indicated their satisfaction level as 9 or 10 out of 10, (10 being the most satisfied), for these attributes was 36%, 38%, and 15% respectively. Clearly, customers believe the current level of service could be improved upon.

Estimated bills are a primary source of customer dissatisfaction. As a result of bi-monthly manual meter reading, over 50% of customer bills are estimated each month. Bill estimates are system-generated based on historical usage. Changes to usage, such as renovations, additional electrical devices, appliances, extended vacation periods, and weather fluctuations, can cause these estimates to be inaccurate. In cases where actual meter reads demonstrate significant changes in consumption patterns, FortisAlberta cancels and re-calculates a new estimate on customers' bills. Approximately 25% of customers each month experience these confusing bills with multiple cancel and re-bill transactions. This is exacerbated by the fact that a percentage of consumption is subject to monthly fluctuating commodity prices.

The manual meter reading process can inconvenience customers, resulting in complaints related to unfamiliar meter readers, property damage (e.g. grass, fence) and access issues. The high turnover of meter readers has contributed to a 25% increase in the number of meter read related customer complaints over the last year.

4.2 Regulatory Compliance

- The *Settlement System Code* requires all cumulative meters to be read within a two-month period and Daily Cumulative Meter transactions (settlement-ready data) must be available for a minimum of 98% of these meters.

- Under the *Alberta Tariff Bill Code*, manual meter reads must be compared to historical values for reasonability; exceptions are reported for investigation and may result in a re-read. Manual re-reads require costly field visits and delay meter data transfer to retailers and customer billing. FortisAlberta completes approximately 18,000 manual re-reads each year.

- Scheduled monthly meter reads and calendar month-end reads are required to support current regulations, such as the *Regulated Rate Option Regulation* AR 262/2005 ("RRO Regulation"). Conventional meter reading practices, where meters are read bi-monthly or monthly, would still result in an estimated calendar month-end read. The RRO Regulation requires the review of commodity prices for regulated customers on a monthly basis and consumption is then billed using a market-driven pricing mechanism. By July 1, 2010, RRO customers will be paying fluctuating market prices for 100% of their commodity requirements.

Despite completing a system-wide re-routing project in 2007 designed to increase meter reading efficiency and improve the percentage of meter reads, FortisAlberta continues to have significant challenges with obtaining regularly scheduled meter reads.

4.3 Measurement Canada

The current federal regulatory environment is favourable for AMI implementations. Changes to federal regulations include the following:

- As a result of the AMI-related activity under the Ontario Smart Meter program, Measurement Canada has provided a *Temporary Permission from Verification and Sealing of Electricity Meters* (ENF-10), which allows utilities implementing AMI over a shortened timeframe to reduce the number of meters exchanged under existing programs. FortisAlberta proposes to follow a similar implementation timeframe as Ontario, and will apply for similar dispensation.

- Changes to *National Policy* (E-26), issued September 15, 2004 by Measurement Canada, will result in increased frequency of mechanical demand meter exchanges. The proposed regulation will require that 100% of mechanical demand meters be exchanged every four years. In contrast, an average 7% of electronic demand meters (such as AMI) need to be sampled after 10 years and then again after another six years. Mechanical demand meters will require four complete exchanges in the timeframe that electronic demand meters will require only two sample exchanges.

4.4 Stakeholder Impacts

The current reliance on estimated reads to perform key financial transactions does not support accuracy of market data. For example, move-in/move-out reads may be contested between customers and retailer switches are subject to the accuracy of the estimates used to transfer sites between retailers. During the final six months of 2006, FortisAlberta processed over 34,000 customer move in/move-out transactions. Had customers or retailers requested actual reads for each move during this period, the off-cycle read costs would have been approximately $1.2 million.

FortisAlberta settles over 45% of Alberta’s electricity load. Without actual meter reads, load settlement could result in unnecessary Pre-Final Error Correction (PFEC) and Post-Final Adjustment Mechanism (PFAM) transactions.

4.5 Economic Drivers

Currently bi-monthly meter reading costs represent approximately 6% of total FortisAlberta operating expense. Increasing fuel and labour costs continue to place upward pressure on FortisAlberta’s meter reading expense, which rose 37% between 2005 and 2006 and is the

Company's second largest contractor expense after brushing costs. For the foreseeable future, there will be continued upward pressure on these costs as the provincial economy continues in a growth environment.

4.6 Efficient Operations and Safety

Meter Reader Turnover

Alberta's economic prosperity continues to result in difficulty hiring and retaining a full complement of meter reading staff by FortisAlberta's contract meter reading vendor. The turnover rate remains high at 75% in 2005 and 53% in 2006, and directly affects FortisAlberta's ability to consistently obtain accurate meter reads in a timely manner.

The meter reader turnover rate increased late in the fall of 2006. As a result, the percentage of cumulative meters with at least one meter read dropped from 97.3% for the period from October to December 2005 to 94.6% for the same period in 2006.[2] Retaining qualified personnel for manual meter reading is expected to remain a challenge in the near term, resulting in an increased number of estimated meter reads in the billing process.

Inefficient Allocation of Resources

The manual meter reading process drives the inefficient use of FortisAlberta field personnel, including Power Line Technicians, to perform meter reads and re-reads rendering them unavailable for higher quality work such as system maintenance and capital construction.

Safety and Accessibility

FortisAlberta's meter readers drive over 6 million kilometers to acquire primarily bi-monthly reads in all weather conditions. Safe driving is always a concern as are poor weather and road conditions. Many secondary roads do not receive the benefit of snow removal, making it difficult for meter readers to reach metered sites in the winter. Flooding during the spring, gated facilities and secured oilfield sites also hamper access to metered sites and reduce meter reading efficiency. Dog bite incidents and oilfield sites with potential H_2S exposure are a growing threat

[2] FortisAlberta Wire Owner Service Quality and Reliability reports for Q4-2005 and Q4-2006

to meter reader safety. Missed reads for all these reasons impact billing accuracy and one missed read could result in a four-month period of estimated billing.

4.7 Environmental Drivers

The Government of Canada estimates that a single occupant vehicle produces 0.20 kg of CO_2 per kilometer. With meter readers traveling approximately 6 million kilometers per year (equivalent to over 9,000 round trips between Edmonton and Calgary), the CO_2 emissions equal 1,120,000 kg, or 1,120 metric tonne.

5. Business Case Methods and Assumptions

5.1 Analysis Period

This business case details FortisAlberta's AMI Phase II Deployment projected cash flows and revenue requirement over the twenty-year period from 2008-2027; twenty years represents the expected life of the AMI electronic meters.

5.2 Comparative Analysis

Included is a comparative financial analysis of the following three alternatives:

- AMI Phase II Deployment;
- Monthly Manual Meter Reading; and
- Bi-Monthly Manual Meter Reading (status quo).

5.3 Assumptions and Data Sources

The costs presented in this analysis include those capital and operating costs that would exist under each alternative over the analysis period. Where services or inventory are being provided by a vendor, contractual costs are included in the analysis. Contract costs are based on a three-year implementation time frame.

General Assumptions

- Discount Rate – 7.0%

- Internal Labour escalation – 2008-2009 – 5%; 4.5% thereafter
- Inflation – 2.6% in 2008, 2.5% thereafter
- Capital Cost Allowance (Class 1) – 4.00%
- Meter Depreciation – 5.72%
- Engineering and Supervision – 8.0% in 2008, 7.5% thereafter
- Income Tax Rate (combined federal and provincial on equity):
  2007 – 31.0%
  2008 – 30.5%
  2009 – 30.0%
  2010 – 29.0%
  2011 – 28.5%
- Return:
  Equity Component – 37.00%
  Debt Component – 63.00%
  Equity Return – 9.00%
  Debt Return – 6.00%

6. Evaluation of Alternatives

This business case includes the analyses of two options to FortisAlberta's AMI Phase II Deployment: the Monthly Manual Meter Reading alternative and the Bi-Monthly Manual Meter Reading alternative which is a business-as-usual model maintaining the current meter reading schedule. Neither alternative matches the functionality of the proposed AMI system.

A summary of the two manual meter reading alternatives is provided below.

6.1 Monthly Manual Meter Reading Alternative

The forecast costs of this alternative are related to operating a monthly manual meter reading system in comparison to the AMI alternative. Assuming that the necessary meter reading resources could be found in Alberta's current labour market, this alternative would not guarantee improved reading accuracy. It would also fail to address customer concerns regarding meter reads for move-in/move-out, retailer switch, site access issues, or provide month-end transition rate changes required to meet the RRO regulation.

Cumulative costs are provided in Table 6.1 for the 2008-2009 test period and the 20-year analysis period; a description of line items follows.

Table 6.1 Incremental Capital and Operating Costs
Monthly Manual Meter Reading Alternative

Description	Forecast 2008/2009 ($000)	Forecast 2008/2027 ($000)
Capital Expenditures		
Increased labour costs due to loss of ENF-10 (dispensation) / E26 (sampling)	$346	$5,564
Purchase of additional handhelds for monthly meter reading	246	246
Corporate E&S	47	439
Total Capital Expenditures	**$639**	**$6,249**
Operating Expense		
Operating Costs – Manual Contract Meter Reading	$28,557	$361,689
Operating Expense – Field Service – billing inquiries	1,474	22,676
Contract Labour for meter reading validation	492	7,550
Software / Hardware increase in support	74	932
Total Operating Expense	**$30,597**	**$392,847**
Total Cost	**$31,236**	**$399,096**

(Totals may vary due to rounding.)

Table 6.1A Description of Capital and Operating Costs
Monthly Manual Meter Reading Alternative

Line Item	Description
Increased labour costs ENF-10 (dispensation) / E26 (sampling)	If manual meter reading continues within FortisAlberta, internal labour costs related to meter sampling would increase due to changes in Measurement Canada sampling requirements. Additionally, FortisAlberta could not apply to Measurement Canada for dispensation provided to AMI projects that improve the accuracy of conventional meters.
Purchase of additional handhelds for monthly meter reading.	With manual monthly meter reading, additional handheld meter reading devices would need to be purchased.
Operating Costs – Manual Contract Meter Reading	Moving to manual monthly meter reading would increase contract costs by approximately 80%, factoring in that certain overhead costs to read bi-monthly meters would increase at the same rate (such as fuel charges, cell phones or safety equipment).
Operating Expense – Field Service – billing inquiries	As additional reads are obtained and reviewed, field validations would increase.
Contract Labour for meter reading validation	As additional reads are obtained, validation exceptions would increase as rules would be applied to more reads, subject to weather / customer load profile changes.
Software / Hardware increase in support	Vendor costs related to support for the additional hardware above would increase.

6.2 Bi-Monthly Manual Meter Reading Alternative

This alternative identifies bi-monthly manual meter reading costs and the financial impact if the AMI Phase II Deployment does not proceed. For example, additional meters would need to be exchanged as a result of the loss of the one-time Measurement Canada dispensation. Another significant impact would be the need to review FortisAlberta's overall meter reading operation, as it does not currently support the meter reading standard in the Settlement System Code requirements and other regulatory initiatives, such as flow-through pricing.

Cumulative costs are provided in Table 6.2 for the 2008-2009 test period and the 20-year analysis period.

Table 6.2 Incremental Capital and Operating Costs
Bi-Monthly Manual Meter Reading Alternative

Description	Forecast 2008/2009 ($000)	Forecast 2008/2027 ($000)
Capital Expenditures		
No reduction in meter services compliance testing	$0	$1,319
No reduction in field services compliance testing	0	2,736
No decrease in capital costs for IT	0	719
Increase in cost for replacement meter program	0	4,341
Corporate E&S	0	684
Total Capital Expenditures	**$0**	**$9,799**
Operating Expense		
Operating Costs – Manual Contract Meter Reading	$17,393	$219,407
Telecom costs not realized with manual meter reading	(533)	(13,242)
Increased labour costs due to loss of ENF-10 (dispensation)/E26 (sampling)	346	5,564
Reduction in Contract Labour for meter reading validation not realized	112	5,602
Reduction in Operating Expense - billing inquiries savings not realized	117	7,240
Total Operating Expense	**$17,435**	**$224,571**
Total Cost	**$17,435**	**$234,369**

(Totals may vary due to rounding.)

6.3 Summary Comparison

A summary comparison of the 2008-2027 cumulative costs for the three alternatives are provided in Table 6.3.

Table 6.3 Incremental Capital and Operating Costs 2008-2027 Forecast

Description	AMI Phase II ($000)	Monthly Manual ($000)	Bi-Monthly Manual ($000)
Capital Expenditures			
Capital Expenditures	$99,647	$5,811	$9,115
Capital Offsets	(11,795)	0	0
Corporate E&S	6,698	438	684
Net Capital Expenditures	**$94,550**	**$6,249**	**$9,799**
Operating Expense			
Operating Expense	$41,268	$392,847	$237,813
Operating Offsets	(13,292)	0	(13,242)
Net Operating Expense	**$27,976**	**$392,847**	**$224,571**
Total Cost	**$122,526**	**$399,096**	**$234,369**

(Totals may vary due to rounding.)

7. Financial and Operational Impacts

7.1 Net Present Value

Table 7.1 provides a summary of the incremental net present value and payback year for the AMI Phase II Deployment relative to the Monthly Manual Meter Reading and Bi-Monthly Manual Meter Reading alternatives.

Table 7.1 Incremental Net Present Value of AMI Phase II Deployment

Description	Incremental to Monthly Meter Reading ($000)	Incremental to Bi-Monthly Meter Reading ($000)
20 year Net Present Value (2008 - 2027)	$93,663	$10,812
Payback year (using cumulative cash flow)	2015	2019

Both bi-monthly and monthly meter reading costs are escalated at 2.6% in 2008 and 2.5% per year thereafter. If such costs were to escalate at 3.6% in 2008 and 3.5% per year thereafter (which is still less than internal labour cost escalations), the impact to the net present value in 20 years would be $107.6 million for monthly manual meter reading and $17.4 million for bi-monthly manual meter reading.

7.2 Incremental Revenue Requirement

The AMI Phase II Deployment is forecast to result in the 2008-2009 revenue requirement reduction shown below (over the Monthly Manual Meter Reading alternative). A working spreadsheet of the forecast revenue requirement from 2008 - 2027 is attached in Attachment R-2.

Table 7.2 AMI Phase II Deployment
Incremental Revenue Requirement 2008-2009

Incremental Revenue Requirement	Forecast 2008 ($000)	Forecast 2009 ($000)
Return	$1,589	$5,421
Depreciation Expense	658	2,942
Operating Expense	(8,144)	(10,021)
Income Tax	413	1,475
Total Incremental Revenue Requirement	**$(5,484)**	**$(183)**

(Totals may vary due to rounding.)

7.3 Benefits

Quantified Benefits

This analysis compares the Monthly Manual Meter Reading alternative as an offset to the AMI Phase II Deployment costs. The total benefit of the AMI over the 20-year analysis period on revenue requirements is $70.2 million and the reduction in 2008-2009 revenue requirements is $5.7 million.

Qualitative Benefits

AMI technology is strongly aligned to FortisAlberta's core operating principles, allowing for the delivery of strong customer service, improved safety performance, and more efficient operations. These principles are essential to successful utility operation for the benefit of customers over the long term. The key benefits presented by AMI effectively address all of the business drivers identified in Section 4.

The opportunities presented by AMI technology are further explored in Attachment R-3.

Benefits of Three Year Implementation

FortisAlberta is proposing a three-year AMI Phase II Deployment schedule to maximize opportunities and address potential customer issues and risks. The proposed timeframe is considered feasible and has become the industry standard. Over 90 electric utilities in Ontario, representing over 4.5 million meters, and others in the U.S. are planning to implement in the same timeframe or expedite implementations even faster than that proposed by FortisAlberta.

The three-year implementation period addresses a number of risks and concerns, and includes the following mitigation strategies.

- *Reduces cost uncertainties.* Capital costs and vendor pricing are secured for full deployment over three years. The cost of AMI vendor services is subject to increase beyond the three-year timeline.
- *Improves customer billing.* Customers' concerns regarding billing on estimates will be addressed with the move to actual monthly meter reading. A three-year deployment schedule is already considered too slow for some customers and competitive retailers.
- *Equitable for customers.* A deployment strategy that ends beyond 2010 would extend the period in which there are two different levels of customer service. Those without AMI would continue to be read bi-monthly and receive estimated bills.
- *Timely realization of economic benefits.* An extended schedule would delay operational savings and benefits, and would temporarily increase costs as FortisAlberta maintained two separate systems.
- *Market change preparedness.* The planned deployment schedule will allow for installations to be completed in time for the transition to 100% market-based regulated rate option pricing in July 2010.

- *Utilizes regulatory dispensation.* Measurement Canada policy aimed at supporting rapid AMI transition projects, such as the one in Ontario, will increase future capital costs on a delayed AMI system.
- *Limits exposure to labour market risks.* Meter reader attrition issues will be limited to the proposed implementation timeline.
- *Opportunities for industry stakeholders.* Access to and participation by all FortisAlberta's customers to industry changes, such as the implementation of retailer dynamic billing, time-of-use billing, and certain demand side management initiatives.

8. Timing Risk

Hardware costs account for a significant portion of the project costs. The current AMI vendor contract negotiated by FortisAlberta is based upon a fixed price for a forecast implementation of three years. If Phase II is not approved or is extended over a longer period, these implementation costs are not guaranteed. Many North American utilities are proposing AMI implementations within their territories; as the number of deployments increase, access to vendors and equipment has become scarce, and continue to become scarcer, placing upward pressure on costs.

9. Conclusion and Recommendation

Monthly meter reads are required to support the accurate calculation of customer bills. The timeliness of meter reads and other functionality supported by an AMI system far exceed those that can be provided through any form of manual meter reading. FortisAlberta's proposal to migrate to monthly meter reads through the deployment of AMI by 2010 will allow customers to visibly see improvements in customer service while minimizing the financial impact of revenue requirements. In the future, customers will realize a reduction in overall cost associated with the meter data management functions that drive many key financial transactions in the Alberta electricity market.

With the demonstrated capability of the AMI technology chosen in Phase I and a positive net present value forecast for full deployment, FortisAlberta is recommending continuation of AMI deployment over 2008, 2009, and 2010. The viability of a three-year implementation period is favourable from both an economic standpoint and operational feasibility perspective.

AMI is an enabling technology. FortisAlberta is proposing to implement the AMI system in a prudent, step-by-step manner to allow for immediate realization of customer benefits while building a technology platform on which future applications can be introduced. These applications, such as integrated outage management, voltage monitoring, and time-of-use billing, will further leverage the proposed AMI system and allow it to evolve with changing customer and market needs.

Given the importance of meter reads in the electricity market, this technology will fundamentally improve the manner in which FortisAlberta will serve customers and retailers. Virtually all market participants stand to gain from the implementation of AMI. FortisAlberta will be able to more effectively manage its operations, retailers can provide customers with more options, and customers can participate more positively in their own energy management.

10. Appendices

Attachment R-1
AMI Phase I Objectives

The objectives of Phase I were to:

- Select an enabling AMI technology through a formal RFP process;
- Implement the selected technology solution in over 25,000 sites, based on varied rate classes, terrains and locations in FortisAlberta's diverse service territory;
- Test the system functionality to assess if monthly meter reading, at a minimum, could be achieved;
- Collect budgetary requirements for installation and maintenance of the system, both from an operational and capital perspective; and
- Update the original business case filed as part of the 2006/2007 DTA with verified information.

An AMI system supports many features beyond meter reads, including multi-utility applications (joint application to obtain meter reads from electric, gas and water meters), outage management, demand side management (time-of-use billing and critical peak pricing), voltage monitoring, and remote disconnection and reconnection of services. These features were not specifically tested in Phase I, although FortisAlberta has confirmed their existence and included them as part of contracted functional requirements of its AMI system.

Technology and Vendor Selection

In order to ensure that the AMI technology selected would best meet FortisAlberta customers' needs and operational requirements, FortisAlberta followed an extremely thorough selection process. The initial capital cost of the proposed system and longer term maintenance costs of operating the system had to be justifiable and reflective of the required customer benefits. The chosen vendor would also need to demonstrate commitment to the project, financial strength and proven operational capability to support the size and complexity of FortisAlberta's installation. Other key factors taken into consideration in the vendor and AMI technology evaluation process included:

- Established manufacturing capability with mass production systems with support services able to deal with large projects;
- Scalability of network and data transmission management that can accommodate in excess of 2,000,000 meters;
- Compatibility with Measurement Canada regulated processes for both software and multiple meters;
- AMI system operability does not interfere with existing distribution and transmission system operations;
- Ability to integrate with multiple AMI water and/or gas meters;
- Ability to capitalize on a longer seal period through the integration of AMI modules with new solid-state meters; and
- Proven functionality with reading resolution capable of hourly intervals, ensuring availability of potential future data requirements.

The selection process included:

- *Vendor Selection Committee.* A Vendor Selection Committee was put in place to review the proposals, with representatives from all impacted areas within FortisAlberta including Customer Service, Operations & Engineering, Information Technology, and Legal.

- *Request for Proposal.* A formal RFP was issued in March 2006, which outlined detailed FortisAlberta requirements. Twelve vendors responded to the RFP.

- *Evaluation and selection of technology.* Based on a thorough review, the Vendor Selection Committee recommended an AMI system based on PLC technology. PLC technology has an established track record throughout North America in rural environments and is most suitable for FortisAlberta territory.

- *Reference checks.* FortisAlberta conducted reference checks with electric utilities who had implemented the proposed technologies, independent of the vendors, to confirm the representations made by the vendors.

- *Contract negotiation and award.* To secure pricing for the entire customer base during Phase I, FortisAlberta was able to select and negotiate a contract with Hunt Technologies for the delivery of AMI equipment and installation services through the end of 2010, pending regulatory and other approvals. Negotiations were completed on December 18, 2006.

Hunt Technologies was selected based on its ability to meet FortisAlberta's key requirements. One of the most significant of these is their strong, user-friendly IT system that effectively manages AMI. The application system architecture is very compatible with FortisAlberta's existing IT systems and allows for data exchanges with multiple systems through easy, secure, and commonly adhered to, non-proprietary data exchange protocols, like XML, CSV, HTML and links to ODBC interfaces. These requirements were critical to ensure that FortisAlberta could continue to meet market driven requirements including potential changes to Settlement System Code and the Tariff Bill Code.

Hunt Technologies

Founded in 1985, Hunt Technologies currently has over six million AMI endpoints deployed.

Hunt has more than 480 utility customers worldwide and maintains and reports a 96% customer satisfaction rating. Hunt provides AMI solutions to investor-owned utilities, rural electric cooperatives, and public utilities. Hunt maintains strong relationships with major meter vendors and provides FortisAlberta flexibility to select meters based on meter functionality and cost. In September 2006, Hunt technologies purchased Stat Signal, a radio frequency ('RF') based AMI solution, and today is the first AMI vendor capable of offering RF and PLC technologies under a single integrated solution. The following map identifies Hunt's installations in North America.

(The map provided above is with permission of Hunt Technologies)

Hunt Technologies was acquired by the Bayard Group in 2006. With annual sales exceeding $1 billion, the Bayard group is an international company that invests in and develops businesses with AMI solutions. The Bayard Group has invested in AMI solutions because of their role in supporting the environment and reducing resource requirements through initiatives like demand side management and load control. Bayard serves 26% of the North America AMR market and is a leader in AMI deployment in North America.

Phase I Field Implementation Results

As of June 1, 2007 approximately 15,000 AMI meters have been installed. The AMI project complexities, including the installation of substation collection devices, the mass meter exchange processes and the implementation of IT interfaces, have been completed. The AMI system is operating as expected and is able to produce daily reads that have been used to generate customer bills. By the end of year, a total of 25,000 AMI meters will be installed in Stony Plain, Nisku, Leduc, Brooks, and Vauxhall.

The following meter reading performance capabilities have been confirmed:

- The capture of actual regular scheduled billing and off-cycle meter reads, including move-in/move-out and retailer switches;
- The efficient transition from bi-monthly to monthly reads and automation of the manual meter reading process;
- The reduction of operational time to validate manual meter reading exceptions in Customer Service; and
- The receipt of actual meter reads supports the Settlement System Code standards.

Certain customer service objectives were confirmed as a direct benefit of collecting additional information through an AMI system. The system can report information on customer usage, power quality, outage notifications, and outage restoration without any additional modifications to FortisAlberta's distribution or IT systems.

Phase I deployment of AMI technology in FortisAlberta's service territory has confirmed that the AMI system operates in a manner consistent with the performance objectives established in the contract, and the core benefits of improved bill accuracy and reduced operating costs will be realized.

Phase I Cost Information

Phase I objectives included proving the cost of implementations and determining if benefits could be economically achieved.

The meters purchased through the Phase I AMI initiative were combined with the purchase of conventional meters. The purchase of conventional meters is tracked as part of the change to the "Uninstalled Meter Inventory" account. The metrology of the meters is the same, the only distinction being that an AMI-enabled meter includes an extra communications card to enable remote AMI data collection. The combination of these two programs over the 2006/2007 period has resulted in the expected replacement of 25,000 conventional meters with AMI-enabled meters, permanently displacing the operating costs associated with manually reading these meters. This reduction has been factored into the meter reading operating budget for 2008 and 2009. The conventional meters removed from customer premises were, where appropriate, redeployed through the ongoing meter exchange program. The uninstalled meter program therefore had a net reduction of $1.7 million in 2006/2007.

The net cost of the Phase I Automated Metering Reading project, including E&S, was $329,000 in 2006 and is forecast to be $6.9 million in 2007. When offset by the net reduction of $1.7 million for the uninstalled meter program, the net incremental cost of Phase I is forecast to be $5.5 million over the two-year period.

Attachment R-2
AMI Phase II Deployment Working Spreadsheet

C:\files\amr\Final
AMI Business Case\Su

Attachment R-3
Opportunities Presented by AMI Technology

While the feasibility of AMI technology and this business case have focused on operational efficiencies and cost reductions for contracted manual meter reading, the following table provides a more comprehensive list of the quantifiable and non-quantifiable benefits that FortisAlberta anticipates will be available with full implementation. Additional capital expenditures and, in some instances, government policy changes may also be required to realize the full benefits of these opportunities.

The following table identifies the benefits associated with AMI technology, which are divided into three categories:

- "**Base** Features" include benefits that will be realized on full implementation of the proposed technology and are included in this business case. These features have been tested and applied in AMI deployments throughout North America.

- "**Enhanced** features" are those that require additional capital expenditures, government policy changes, or third-party involvement to operationally deploy the technology. FortisAlberta has ensured that the AMI system selected is technically capable of supporting the enhanced functionality, such as remote disconnect and reconnect, but has not included the additional capital cost or benefits related to implementing these changes as part of this business case.

- "**Future** features" are those that, in FortisAlberta's assessment, are in development phase and have not been deployed *en-mass*. Most of these features would require additional government policy support and significant restructuring of the marketplace to implement.

Table A3

	Base Features	Enhanced Features	Future Features
Benefits for end-use customers: • Actual meter reads will reduce the need for cancel/re-bills or true-up bills. These fluctuations are of particular concern to customers on pre-authorized withdrawal; • Customers will receive actual consumption data about pricing changes, retailer switches, and move-in / move-out; • A strong and verifiable audit trail for customers, retailers and internal stakeholders will exist; • The ability to review and determine value of competitive retail offers; • Accurate billing will result in increased customer satisfaction; • Remote access to reads will eliminate inconvenience for customers with inside meters (intrusion into the home, management of keys, etc.); • Accurate billing of distributed generation opportunities; and • Customer understanding of energy usage patterns will allow for comparison of competitive retailer options.	√		
Meter Reading: • Replace manual meter reading costs; • Transition customers to monthly reads; • Eliminate inflationary pressure (long-term labour costs for contract meter reading); • Eliminate meter reader resource pressure; • Reduction of off-cycle meter reading costs; and • Eliminate meter reader special training and safety issues related to hazardous services.	√		
Meter fleet maintenance costs: • Upgrade electro-mechanical meter fleet to electronic meters, subject to statistical sampling; • Reduction of re-verification and meter exchange costs; and • Reduction of meter exchange costs resulting from the Temporary Permission from Verification and Sealing of Electricity Meters for utilities that are implementing AMI infrastructure.	√		
Operations: • Improve meter data accuracy, retrieval and precision; • Reduction of resources for the validation of questionable manual meter reads;	√		

	Base Features	Enhanced Features	Future Features
• Reduction in cancel/re-bill transactions; • Improve customer service with on-demand reads; • Identification of power theft and meter tampering; • Increase accuracy of load settlement results and reduction in variability between initial and interim settlements; and • Increase accuracy of load profiles (customer load profiling).			
Retailer Pricing Options: • Enhance customer choice and retail competition opportunities by providing more frequent reads for the creation of dynamic pricing plans; • Manage transition to variable energy pricing (June 30, 2010) – RRO regulation; and • Enhance system capability to produce hourly and Time-Of-Use reads, as well as hourly peak demand.		√	
REA Meter Reads: • Opportunity to cost-share or provide meter reading services to REAs that share common feeders. FortisAlberta has been advised by REAs that they are interested in jointly working to implement and share costs of Power Line Communication-based AMI systems for their customers.		√	
Outage Management: • Opportunity to integrate outage detection with an outage management system; • Opportunity to improve system reliability by identifying sites that may have power issues; and • Opportunity to improve notification of power restoration.		√	
Customer Service – FortisAlberta & Retailers: Current: • Decline in call volumes with the use of actual reads for billing; • Accurate meter read data used by Retailers for determination of energy procurement; • Accurate calculation of franchise fee and A1 rider and payment; and • Efficient handling of calls with the availability of actual meter reads for discussions with FortisAlberta customers. Future: • Opportunity to obtain automatic notification of power outages to assist in quicker restoration of service resulting in reduced customer damage claims and value of claims; • Opportunity for commercial customers to receive automatic	√ (Current)	√ (Future)	

	Base Features	Enhanced Features	Future Features
notification of power outage to assist with reducing spoilage, cold temperature damage to product, etc.; • Allow customer selected billing dates; • Enable power quality analysis; • Retailer identification of high-risk bad debt scenarios; • Access to consumption data to allow for better forecasting commodity purchases; and • Opportunity for summary billed customers to have multiple sites billed on the same date, simplifying retailer customer billing.			
Field Services: Current • Reduce FortisAlberta field service time required for meter read verification orders. Future • Reduction of FortisAlberta field service time for disconnect/connect work orders (benefit dependent on sites equipped with remote connect/disconnect hardware); • Enhancement of data to assess voltage sags and swells; • Opportunity to enhance real-time analysis of the service area to streamline asset planning; and • Opportunity to collect data for engineering studies for distribution system planning, system optimization, planning, and prevention of equipment failure.	√	√	
Environmental Impact: Current • Reduction of vehicle usage for meter readers and field staff, resulting in less risk of traffic accidents and vehicle maintenance; and • Reduction in greenhouse gas emissions. Future • Opportunity to support net billing services for micro-generation and promote green power initiatives; and • Enhancement of customer capability to manage power costs and usage through actual data and Demand Side Management.	√		√

FortisAlberta
Capital Project Analysis
Advanced Metering Infrastructure (Monthly Manual Meter Reading)
In $000 Canadian

Line No.		Reference	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	SUMMARY																					
	Revenue Requirements																					
	Return on Equity (no mid-year assumption)		744	2,539	3,155	2,933	2,712	2,497	2,283	2,065	1,847	1,635	1,426	1,209	995	782	569	357	145	(66)	(277)	(487)
	Return on Debt (Interest Expense)		845	2,882	3,581	3,329	3,079	2,834	2,591	2,344	2,097	1,856	1,618	1,373	1,129	888	646	405	165	(75)	(314)	(552)
	Depreciation Expense		658	2,942	5,246	5,903	5,859	5,819	5,782	5,741	5,694	5,649	5,609	5,563	5,509	5,456	5,401	5,342	5,282	5,220	5,154	5,086
	Operating Expense		(8,144)	(10,021)	(14,705)	(15,617)	(16,039)	(16,473)	(16,920)	(17,379)	(17,851)	(18,337)	(18,837)	(19,351)	(19,880)	(20,425)	(20,985)	(21,561)	(22,154)	(22,764)	(23,392)	(24,038)
	Income Tax		413	1,475	1,974	1,973	1,942	1,910	1,877	1,839	1,797	1,756	1,713	1,665	1,614	1,562	1,508	1,451	1,392	1,331	1,269	1,204
	Total Revenue Requirement for Project		**(5,484)**	**(183)**	(748)	(1,479)	(2,446)	(3,413)	(4,387)	(5,390)	(6,416)	(7,441)	(8,472)	(9,541)	(10,634)	(11,736)	(12,861)	(14,006)	(15,169)	(16,354)	(17,560)	(18,788)
	Net Present Value of Revenue Requirement	**7.00%**	**(70,166)**																			
	Rate Impact																					
	Forecast Revenue Requirements		**260,500**	**290,100**																		
	Rate Impact		**-2.11%**	**-0.06%**																		
	Incremental Capital Cost																					
	New Automated Meter Reader		23,459	57,031	23,858	(509)	(499)	(495)	(496)	(500)	(508)	(519)	(532)	(548)	(566)	(586)	(608)	(632)	(657)	(685)	(713)	(744)
	Avoided Capital Repair		(458)	(181)	(122)	(266)	(250)	(166)	(147)	(294)	(342)	(194)	(161)	(377)	(379)	(331)	(397)	(403)	(410)	(440)	(456)	(475)
	Cash Outlay in Year		23,001	56,850	23,736	(775)	(750)	(661)	(642)	(794)	(850)	(713)	(693)	(925)	(945)	(917)	(1,005)	(1,035)	(1,068)	(1,125)	(1,169)	(1,219)
	Annual Operating Costs / (Savings)																					
	Total Annual Operating Costs (Savings)		(8,144)	(10,021)	(14,705)	(15,617)	(16,039)	(16,473)	(16,920)	(17,379)	(17,851)	(18,337)	(18,837)	(19,351)	(19,880)	(20,425)	(20,985)	(21,561)	(22,154)	(22,764)	(23,392)	(24,038)
	Depreciation Expense																					
	Opening Cash Outlay		0	23,001	79,851	103,587	102,812	102,063	101,402	100,760	99,966	99,116	98,403	97,709	96,784	95,839	94,922	93,917	92,882	91,814	90,689	89,520
	Additions in Year		23,001	56,850	23,736	(775)	(750)	(661)	(642)	(794)	(850)	(713)	(693)	(925)	(945)	(917)	(1,005)	(1,035)	(1,068)	(1,125)	(1,169)	(1,219)
	Cumulative Total		23,001	79,851	103,587	102,812	102,063	101,402	100,760	99,966	99,116	98,403	97,709	96,784	95,839	94,922	93,917	92,882	91,814	90,689	89,520	88,301
	Depreciation Rate - Advanced Metering Infrastructure		5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%	5.72%
	Depreciation Expense (1/2 year rule)		658	2,942	5,246	5,903	5,859	5,819	5,782	5,741	5,694	5,649	5,609	5,563	5,509	5,456	5,401	5,342	5,282	5,220	5,154	5,086
	Capital Cost Allowance																					
	Opening Balance - UCC		0	22,541	77,353	97,519	92,860	88,411	84,227	80,228	76,241	72,358	68,765	65,335	61,815	58,416	55,181	51,989	48,895	45,893	42,955	40,091
	Total Cash Outlay		23,001	56,850	23,736	(775)	(750)	(661)	(642)	(794)	(850)	(713)	(693)	(925)	(945)	(917)	(1,005)	(1,035)	(1,068)	(1,125)	(1,169)	(1,219)
	Subtotal UCC		23,001	79,391	101,088	96,745	92,110	87,750	83,584	79,434	75,391	71,645	68,072	64,410	60,869	57,499	54,176	50,954	47,827	44,768	41,785	38,872
	Capital Cost Allowance Rate - Class 1		4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
	CCA on Opening Balance		0	902	3,094	3,901	3,714	3,536	3,369	3,209	3,050	2,894	2,751	2,613	2,473	2,337	2,207	2,080	1,956	1,836	1,718	1,604
	CCA on Capital Expenditures (1/2 year rule)		460	1,137	475	(15)	(15)	(13)	(13)	(16)	(17)	(14)	(14)	(19)	(19)	(18)	(20)	(21)	(21)	(22)	(23)	(24)
	Total CCA		460	2,039	3,569	3,885	3,699	3,523	3,356	3,193	3,033	2,880	2,737	2,595	2,454	2,318	2,187	2,059	1,934	1,813	1,695	1,579
	Ending Balance UCC		22,541	77,353	97,519	92,860	88,411	84,227	80,228	76,241	72,358	68,765	65,335	61,815	58,416	55,181	51,989	48,895	45,893	42,955	40,091	37,292
	Regulatory Assumptions																					
	Equity Component		37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%
	Debt Component		63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%	63.00%
	Equity Return		9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
	Debt Return		6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
	Property Section Of Balance Sheet																					
	Gross Property		23,001	79,851	103,587	102,812	102,063	101,402	100,760	99,966	99,116	98,403	97,709	96,784	95,839	94,922	93,917	92,882	91,814	90,689	89,520	88,301
	Accumulated Depreciation		(658)	(3,599)	(8,846)	(14,749)	(20,608)	(26,427)	(32,209)	(37,950)	(43,644)	(49,293)	(54,901)	(60,464)	(65,973)	(71,429)	(76,829)	(82,172)	(87,454)	(92,674)	(97,828)	(102,914)
	Net Book Value		22,343	76,252	94,741	88,064	81,455	74,975	68,550	62,016	55,472	49,110	42,808	36,320	29,866	23,493	17,087	10,710	4,360	(1,984)	(8,308)	(14,612)
	Income Tax Impact																					
	Alberta Income Tax Rate		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%	10.00%	10.00%	10.00%	10.00%	10.00%
	Federal Income tax rate		20.50%	20.00%	19.00%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%	18.50%
	Combined Income Tax Rate		30.50%	30.00%	29.00%	28.50%	28.50%	28.50%	28.50%	28.50%	28.50%	28.50%	28.50%	28.50%	28.50%	28.50%	28.50%	28.50%	28.50%	28.50%	28.50%	28.50%

FortisAlberta
Advanced Meter Infrastructure (AMI) Comparative Analysis - Monthly Manual Meter Reading
Cost Assumptions 2008 - 2027

Alternative: AMI - Phase II

Development of Alternative: This forecast is the capital expenditures for the installation of the AMI system and resulting operation costs/reductions with the implementatior

Cost Assumptions (000's) / Forecast Costs ($000)

Description	Unit	No. of Units			Unit Cost 2007$	2008	2009	2010	Subtotal 2008 - 2010
Capital Expenditures:		2008	2009	2010+					
AMI Phase II Meters	Meter #	51,798	236,434	103,357	0.131592	6,993	32,720	14,661	54,374
Growth for period Jan - Dec 2007, # of meters	Meter #	11,690	2,016	0	0.131592	1,578	279	0	1,857
Substation Hardware	Estimate $	$3,938	$4,052	$1,027		4,041	4,262	1,107	9,410
Installation - internal labour	Estimate $	$4,542	$4,639	$1,509		4,769	5,115	1,738	11,622
Installation - external labour	Estimate $	$5,431	$11,530	$4,348		5,572	12,125	4,687	22,384
Capital Expenditures						22,953	54,501	22,194	99,647
E&S $						1,836	4,088	1,665	7,588
Capital Expenditures including E&S						24,789	58,588	23,858	107,235
Reduction in AMI Meter Capital Cost - Retrofit meters	Estimate $	($1,200)	($1,378)			(1,231)	(1,449)	0	(2,680)
Reduction in Meter Services- AMI compliance testing	Estimate $					0	0	0	0
Reduction in Field Services - AMI compliance testing	Estimate $					0	0	0	0
Reduction in Capital cost - IT	Estimate $					0	0	0	0
Reduction in Replacement Meter Capital Cost - meter purchase	Estimate $					0	0	0	0
Capital Reductions						(1,231)	(1,449)	0	(2,680)
E&S $						(99)	(109)	0	(207)
Capital Reductions including E&S						(1,330)	(1,557)	0	(2,887)
Net Capital Expenditures						21,721	53,052	22,194	96,967
Net E&S						1,738	3,979	1,665	7,381
Net Capital Expenditures including E&S						23,459	57,031	23,858	104,348
E&S rate %						8.00%	7.50%	7.50%	
Operating Expense		2008	2009	2010	2011+				
External meter reading and systems operating costs	Estimate $	$6,758	$5,218	$1,230	$594	6,934	5,487	1,326	13,747
Telecom	Estimate $	$118	$392	$527	$552	121	412	568	1,101
Reduction in Meter Shop Operating Expense- replacement conventional meters	Estimate $					(47)	(49)	(51)	(146)
Reduction in Operating Expense - Field Services - replacement conventional meters	Estimate $					(96)	(101)	(106)	(304)
Reduction in Contract Labour for meter reading validatior	Estimate $	$0	($101)	($177)	($177)	0	(112)	(204)	(316)
Reduction in Operating Expense - Field Service - billing inquiries	Estimate $	($20)	($87)	($230)	($230)	(21)	(96)	(265)	(382)
Total Operating Expense						6,891	5,542	1,267	13,699
Total Cost without E&S						28,612	58,593	23,461	110,666
Total Cost with E&S						30,350	62,572	25,125	118,047

Description	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total	
AMI Phase II Meters																		54,374	
Growth for period Jan - Dec 2007, # of meters																		1,857	
Substation Hardware																		9,410	
Installation - internal labour																		11,622	
Installation - external labour																		22,384	
Capital Expenditures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	99,647	
E&S $	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7,588	
Capital Expenditures including E&S	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	107,235	
Reduction in AMI Meter Capital Cost - Retrofit meters																		(2,680)	
Reduction in Meter Services- AMI compliance testing	(53)	(56)	(58)	(61)	(64)	(66)	(69)	(73)	(76)	(79)	(83)	(87)	(90)	(94)	(99)	(103)	(108)	(1,319)	
Reduction in Field Services - AMI compliance testing	(111)	(116)	(121)	(126)	(132)	(138)	(144)	(150)	(157)	(164)	(172)	(179)	(188)	(196)	(205)	(214)	(224)	(2,736)	
Reduction in Capital cost - IT	(134)	(110)	(90)	(74)	(61)	(50)	(41)	(33)	(27)	(22)	(18)	(15)	(12)	(10)	(8)	(7)	(6)	(719)	
Reduction in Replacement Meter Capital Cost - meter purchase	(175)	(183)	(192)	(200)	(209)	(219)	(228)	(239)	(250)	(261)	(272)	(285)	(298)	(311)	(325)	(340)	(355)	(4,341)	
Capital Reductions	(473)	(464)	(461)	(461)	(465)	(473)	(483)	(495)	(510)	(527)	(545)	(566)	(588)	(612)	(637)	(664)	(692)	(11,795)	
E&S $	(35)	(35)	(35)	(35)	(35)	(35)	(36)	(37)	(38)	(40)	(41)	(42)	(44)	(46)	(48)	(50)	(52)	(891)	
Capital Reductions including E&S	(509)	(499)	(495)	(496)	(500)	(508)	(519)	(532)	(548)	(566)	(586)	(608)	(632)	(657)	(685)	(713)	(744)	(12,686)	
Net Capital Expenditures	(473)	(464)	(461)	(461)	(465)	(473)	(483)	(495)	(510)	(527)	(545)	(566)	(588)	(612)	(637)	(664)	(692)	87,852	
Net E&S	(35)	(35)	(35)	(35)	(35)	(35)	(36)	(37)	(38)	(40)	(41)	(42)	(44)	(46)	(48)	(50)	(52)	6,698	
Net Capital Expenditures including E&S	(509)	(499)	(495)	(496)	(500)	(508)	(519)	(532)	(548)	(566)	(586)	(608)	(632)	(657)	(685)	(713)	(744)	94,550	
E&S rate %	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%		
Operating Expense																			Table 6.3
External meter reading and systems operating costs	657	673	690	707	725	743	761	780	800	820	840	861	883	905	928	951	975	27,445	
Telecom	610	625	641	657	673	690	707	725	743	762	781	800	820	841	862	883	905	13,823	41,268
Reduction in Meter Shop Operating Expense- replacement conventional meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(146)	
Reduction in Operating Expense - Field Services - replacement conventional meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(304)	
Reduction in Contract Labour for meter reading validatior	(214)	(223)	(233)	(244)	(255)	(266)	(278)	(291)	(304)	(317)	(332)	(347)	(362)	(379)	(396)	(413)	(432)	(5,602)	
Reduction in Operating Expense - Field Service - billing inquiries	(277)	(290)	(303)	(316)	(331)	(345)	(361)	(377)	(394)	(412)	(430)	(450)	(470)	(491)	(513)	(536)	(561)	(7,240)	(13,292)
Total Operating Expense	775	785	794	804	812	821	829	837	845	852	859	865	871	876	880	884	887	27,976	
Total Cost without E&S	302	321	334	342	347	348	347	342	335	325	313	299	283	264	244	221	195	115,828	
Total Cost with E&S	267	286	299	308	312	313	311	305	297	286	272	257	239	218	196	171	143	122,526	

***** where changes in operating expenses were considered to be net neutral from current practice to AMI, line items were not entered for example the current ITRON position will no longer exist however that position will become an AMI operator**

Alternative: Manual Monthly Meter Reading

Development of Alternative: This forecast is based upon changes in costs of operating a monthly manual meter reading system in comparison to the AMI alternative

Cost Assumptions / Forecast Costs ($000)

Description	Unit	No. of Units			Unit Cost 2007$	2008	2009	2010	Subtotal 2008 - 2010
Capital Expenditures:		2008	2009	2010+					
Increased labour costs due to loss of ENF-10 (dispensation) / E26 (sampling)	Estimate $					178	168	114	460
Purchase of additional handhelds required for monthly meter readinç	Estimate $	$240				246	0	0	246
Total Capital Expenditures						424	168	114	706
E&S Dollars						34	13	9	55
Total Capital Expenditures including E&S						458	181	122	761
E&S rate %						8.00%	7.50%	7.50%	
Operating Expense									
Operating Costs - Manual Contract Meter Reading	Estimate $	$13,683	$13,805	$13,805		14,039	14,518	14,881	43,438
Operating Expense - Field Service - billing inquiries	Estimate $				$685	719	755	789	2,264
Contract Labour for meter reading validatior	Estimate $				$228	240	252	263	754
Software / Hardware increase in support	Estimate $				$36	37	37	38	112
Total Operating Expense						15,034	15,562	15,972	46,569
Total Cost with E&S						15,492	15,743	16,094	47,329

Description	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Increased labour costs due to loss of ENF-10 (dispensation) / E26 (sampling)	247	233	154	136	273	318	181	150	351	353	308	369	375	382	410	424	442	5,564
Purchase of additional handhelds required for monthly meter readinç	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	246
Total Capital Expenditures	247	233	154	136	273	318	181	150	351	353	308	369	375	382	410	424	442	5,811
E&S Dollars	19	17	12	10	20	24	14	11	26	26	23	28	28	29	31	32	33	438
Total Capital Expenditures including E&S	266	250	166	147	294	342	194	161	377	379	331	397	403	410	440	456	475	6,249
E&S rate %	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	
Operating Costs - Manual Contract Meter Reading	15,253	15,634	16,025	16,426	16,836	17,257	17,689	18,131	18,584	19,049	19,525	20,013	20,514	21,026	21,552	22,091	22,643	361,688
Operating Expense - Field Service - billing inquiries	825	862	901	941	984	1,028	1,074	1,123	1,173	1,226	1,281	1,339	1,399	1,462	1,528	1,597	1,668	22,676
Contract Labour for meter reading validatior	275	287	300	313	328	342	358	374	391	408	427	446	466	487	509	532	556	7,550
Software / Hardware increase in support	39	40	41	42	43	44	46	47	48	49	50	52	53	54	56	57	58	932
Total Operating Expense	16,392	16,824	17,267	17,723	18,191	18,672	19,166	19,674	20,196	20,732	21,283	21,849	22,431	23,030	23,644	24,276	24,926	392,847
Total Cost with E&S	16,658	17,074	17,433	17,870	18,485	19,014	19,361	19,835	20,573	21,111	21,614	22,246	22,834	23,440	24,085	24,732	25,401	399,096

General Assumptions

Annual Inflation	
Internal Labour - 2008	5.0%
Internal Labour - 2009	5.0%
Internal Labour - Post 2009	4.5%
Inflation - 2008	2.6%
Inflation - 2009	2.5%
Inflation - Post 2009	2.5%
Costs have been inflated from the originally stated year o	2007
Sensitivity Factor	
Capital Cost	1.0
Operating Cost	1.0
E&S Factors	
E&S 2008	8.00%
E&S 2009	7.50%
E&S Post 2009	7.50%

FortisAlberta

Advanced Meter Infrastructure (AMI) Comparative Analysis
Incremental Net Present Value 2008-2027 ($000) Monthly Manual Meter Reading

Alternative: AMI (Total capital expenditure for installation of AMI and operating costs to operate the AMI system

Description	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Cost																					
Capital Expenditures	(23,459)	(57,031)	(23,858)	509	499	495	496	500	508	519	532	548	566	586	608	632	657	685	713	744	(94,550)
Operating Expense	(6,891)	(5,542)	(1,267)	(775)	(785)	(794)	(804)	(812)	(821)	(829)	(837)	(845)	(852)	(859)	(865)	(871)	(876)	(880)	(884)	(887)	(27,976)
Total Cost	(30,350)	(62,572)	(25,125)	(267)	(286)	(299)	(308)	(312)	(313)	(311)	(305)	(297)	(286)	(272)	(257)	(239)	(218)	(196)	(171)	(143)	(122,526)
Quantified Benefits																					
Cash Inflow	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Quantified Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Cash Flow	(30,350)	(62,572)	(25,125)	(267)	(286)	(299)	(308)	(312)	(313)	(311)	(305)	(297)	(286)	(272)	(257)	(239)	(218)	(196)	(171)	(143)	(122,526)

Alternative: Business as Usual (Costs to continue to operate a manual meter reading system)

Description	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Cost																					
Capital Expenditures	458	181	122	266	250	166	147	294	342	194	161	377	379	331	397	403	410	440	456	475	6,249
Operating Expense	15,034	15,562	15,972	16,392	16,824	17,267	17,723	18,191	18,672	19,166	19,674	20,196	20,732	21,283	21,849	22,431	23,030	23,644	24,276	24,926	392,847
Total Cost	15,492	15,743	16,094	16,658	17,074	17,433	17,870	18,485	19,014	19,361	19,835	20,573	21,111	21,614	22,246	22,834	23,440	24,085	24,732	25,401	399,096
Quantified Benefits																					
Cash Inflow	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Quantified Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Cash Flow	15,492	15,743	16,094	16,658	17,074	17,433	17,870	18,485	19,014	19,361	19,835	20,573	21,111	21,614	22,246	22,834	23,440	24,085	24,732	25,401	399,096

Incremental Cash Flow (Net cash flow required for installation of the AMI system and future net cash flow savings as a result of the AMI system

Description	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Cost																					
Capital Expenditures	(23,001)	(56,850)	(23,736)	775	750	661	642	794	850	713	693	925	945	917	1,005	1,035	1,068	1,125	1,169	1,219	(88,301)
Operating Expense	8,144	10,021	14,705	15,617	16,039	16,473	16,920	17,379	17,851	18,337	18,837	19,351	19,880	20,425	20,985	21,561	22,154	22,764	23,392	24,038	364,871
Total Cost	(14,857)	(46,829)	(9,031)	16,391	16,788	17,134	17,562	18,173	18,701	19,050	19,530	20,277	20,826	21,341	21,989	22,595	23,222	23,889	24,561	25,257	276,570
Quantified Benefits																					
Cash Inflow	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Quantified Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Cash Flow	(14,857)	(46,829)	(9,031)	16,391	16,788	17,134	17,562	18,173	18,701	19,050	19,530	20,277	20,826	21,341	21,989	22,595	23,222	23,889	24,561	25,257	276,570
Cumulative Cash Flow	(14,857)	(61,687)	(70,718)	(54,326)	(37,538)	(20,404)	(2,842)	15,330	34,032	53,082	72,612	92,889	113,714	135,056	157,045	179,641	202,862	226,751	251,312	276,570	
								Postive Cash Flow													

Incremental Net Present Value

Description	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Discount Rate	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	
Net Present Value	(13,885)	(40,903)	(7,372)	12,505	11,970	11,417	10,937	10,577	10,172	9,684	9,279	9,003	8,642	8,277	7,970	7,654	7,351	7,068	6,791	6,527	93,663

Hydro One Brampton Networks Inc.

Issuance of Addendum for Smart Metering Rates

To The 2007 Distribution Rate Adjustments

ED-2003-0038

EB-2005-0377/ EB-2007-0541

Summary of Application

February 9th, 2007

On January 26th, 2007 Hydro One Brampton Networks Inc. (Hydro One Brampton) filed with the Ontario Energy Board (the "Board"), pursuant to section 78 of the *Ontario Energy Board Act, 1998,* for an Order or Orders approving the revenue requirement and customer rates for the distribution of electricity, to be implemented on May 1, 2007.

As part of this application, Hydro One Brampton requested the Board to approve a smart metering rate rider of $0.52 per metered customer to be implemented on May 1, 2007.

On January 29th, 2007, the Board issued an Addendum to its Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors. This addendum noted that the Board would advise parties of the approval process related to additional smart meter funding. This Addendum provided direction for distributors' recovery of costs associated with smart metering investments in electricity distribution rates and on filing requirements for 2007 EDR smart metering rate adders.

Based on the directions associated with this addendum, Hydro One Brampton has calculated a revised smart metering rate rider that is different from the original rate requested in its application of January 26th, 2007.

Hydro One Brampton is withdrawing its request for approval of a smart metering rate rider of $0.52 per metered customer and is now requesting approval from the Board for a smart metering rate rider of $0.67 per metered customer to be implemented on May 1, 2007.

Hydro One Brampton utilized the standard 2007 EDR Smart Meter Rate Calculation Model as provided by the Board to determine the smart metering rate rider. The following gives a brief explanation of the values used to populate the 2007 EDR Smart Meter Rate Calculation Model.

<u>From Tab 2 Smart Meter Data</u>

<u>Smart Meter Unit Cost</u>

1) Smart Meter Unit Cost

The smart meter unit cost submitted in the application is based on our current invoiced smart metering costs. Theses costs include the material cost of the meter and the communication module under glass. It does not include any customer equipment costs or any required socket adaptors.

2) Smart Meter Other Unit Cost

The costs associated with this data input include the costs of an optional extended outage detection capability. Hydro One Brampton believes there are real customer benefits associated with this function and is building this capability into its ongoing AMI deployment.

3) Smart Meter Installation Cost per Unit

The smart meter installation costs per unit submitted in the application are based on our contractor's current pricing structure.

4) Smart Meter Other Cost Per Unit

Costs in this section include costs associated with meter equipment required to complete this installation of the smart meter such as meter seals and meter rings, licensing and maintenance support per meter. In addition, these costs include the additional cost of a collector on a per meter basis.

<u>AMI Capital Cost</u>

5) AMI Computer Hardware Costs

AMI computer hardware includes the costs of computer servers required to facilitate AMI.

6) AMI Computer Software Costs

AMI computer software includes the costs for software license fees, attending professional services and one time telecom activation fees required to facilitate AMI.

<u>Other Capital Cost</u>

7) Other Computer Hardware Costs

Hydro One Brampton has not included any costs in this section.

8) Other Computer Software Costs

Hydro One Brampton has not included any costs in this section.

<u>Incremental AMI Operational Expenses</u>

9) Incremental AMI O&M Expenses

Hydro One Brampton has not included any costs in this section.

10) Incremental AM&I Admin Expenses

Incremental other operating expenses consist of costs for day to day program management; and project communication and change management.

<u>Incremental Other Operational Expenses</u>

11) Incremental Other O&M Expenses

Hydro One Brampton has not included any costs in this section.

12) Incremental Other Operational Expenses

Hydro One Brampton has not included any costs in this section.

<u>From Tab 3 LDC Assumptions and Data</u>

Hydro One Brampton Has applied the defaulted amortization rates as supplied in model.

Contact Information:

Scott Miller, Regulatory Affairs Manager
Hydro One Brampton Networks Inc.
175 Sandalwood Parkway West
Brampton, Ontario L7A 1E8
Tel (905) 452-5504
Fax (905) 840-0967
smiller@hydroonebrampton.com

DATED at Brampton, Ontario, this 9th day of February, 2007.

HYDRO ONE BRAMPTON NETWORKS INC.

____

Scott Miller

Ontario Energy Board

2007 EDR Smart Meter Rate Calculation Model

Sheet 1 Utility Information Sheet

Legend:	Input Cell	Pull-Down Menu Option	Output Cell
	From Another Sheet	To The 2007 IRM Model	To Another Sheet

Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.

Name of LDC: Hydro One Brampton Networks Inc.

Licence Number: ED-2003-0038

Smart Meter Grouping: Listed

IRM 2007 EB Number: EB-2007-0541

EDR 2006 RP Number: RP-2005-0020

EDR 2006 EB Number: EB-2005-0377

Date of Submission: 09-Feb,2007

Revision: **0**

Version: 1.0

Contact Information

Name: Scott Miller

Title: Regulatory Affairs Manager

Phone Number: (905)-452-5504

E-Mail Address: smiller@hydroonebrampton.com

Please Note: In the event of an inconsistency between this model and any element of the January 2007 "Report of the Board on 2nd Generation Incentive Regulation of Ontario's Electricity Distributors - Addendum for Smart Metering Rates ", the Report governs.

Copyright

This Distribution Rate model is protected by copyright and is being made available to you solely for the purpose of preparing or reviewing an Distribution Rate application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing or reviewing an Distribution Rate applicaiton, you must ensure that the person understands and agrees to the restrictions noted above.

Ontario

2007 EDR Smart Meter Rate Calculation Model

Hydro One Brampton Networks Inc.

EB-2007-0541

09-Feb,2007

Sheet 2. Smart Meter Capital Cost and Operational Expense Data

Smart Meter Unit Installation Plan: *(From Smart Meter Plan filed December 15, 2006)*

assume calendar year installation	2006	2007	2008	2009	2010	Total
Planned number of Residential smart meters to be installed	5,000	30,000	35,000	35,000	27,000	132,000
Planned number of General Service Less Than 50 kW smart meters	-	-	-	-	-	-
Planned Meter Installation (Residential and Less Than 50 kW only)	5,000	30,000	35,000	35,000	27,000	132,000
Planned Meter Installation Completed before January 1, 2008		35,000				

Smart Meter Unit Cost

	Per Unit	
Smart Meter Unit Cost *Enter the invoiced cost per smart meter purchased* *Please provide details in Manager's Summary*	$ 91.80	A
Smart Meter Other Unit Cost *Enter the invoiced other costs per smart meter unit purchased* *Please provide details in Manager's Summary*	$ 16.20	B
Smart Meter Installation Cost per Unit *Enter the time and material cost per smart meter unit installed* *Please provide details in Manager's Summary*	$ 12.30	C
Smart Meter Other Cost per Unit *Enter the other cost per smart meter unit installed* *Please provide details in Manager's Summary*	$ 5.03	D
Total Unit cost per Smart Meter	$ 125.33 *3. LDC Assumptions and Data*	E = A + B + C + D

AMI Capital Cost

	2006	2007	2008	2009	2010	Total	
AMI Computer Hardware Costs *Enter the estimated capital costs for AMI related Computer Hardware* *Please provide details in Manager's Summary*		$ 200,000	*3. LDC Assumptions and Data*			$ 200,000	F
AMI Computer Software Costs *Enter the estimated capital costs for AMI related Computer Software* *Please provide details in Manager's Summary*	$ -	$ 300,000	*3. LDC Assumptions and Data*			$ 300,000	G
Total AMI Capital Cost	**$ -**	**$ 500,000**	**$ -**	**$ -**	**$ -**	**$ 500,000**	H = F + G

Other Capital Cost

	2006	2007	2008	2009	2010	Total	
Other Computer Hardware Costs *Enter the estimated capital costs for other related Computer Hardware* *Please provide details in Manager's Summary*	$ -	$ -	$ - *3. LDC Assumptions and Data*	$ -	$ -	$ -	I
Other Computer Software Costs *Enter the estimated capital costs for other related Computer Software* *Please provide details in Manager's Summary*	$ -	$ -	$ - *3. LDC Assumptions and Data*	$ -	$ -	$ -	J
Total Other Capital Cost	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	K = I + J

Incremental AMI Operational Expenses

	2006	2007	2008	2009	2010	Total	
Incremental AMI O&M Expenses *Enter the estimated incremental AMI related O&M expenses* *Please provide details in Manager's Summary*			*3. LDC Assumptions and Data*			$ -	L
Incremental AMI Admin Expenses *Enter the estimated incremental AMI related Admin expenses* *Please provide details in Manager's Summary*	$ 54,000	$ 410,000	$ 670,000 *3. LDC Assumptions and Data*	$ 860,000	$ 1,050,000	$ 3,044,000	M
Total Incremental AMI Operation Expenses	**$ 54,000**	**$ 410,000**	**$ 670,000**	**$ 860,000**	**$ 1,050,000**	**$ 3,044,000**	N = L + M

Incremental Other Operational Expenses

	2006	2007	2008	2009	2010	Total	
Incremental Other O&M Expenses *Enter the estimated incremental Other related O&M expenses* *Please provide details in Manager's Summary*	$ -	$ -	$ - *3. LDC Assumptions and Data*	$ -	$ -	$ -	O
Incremental Other Admin Expenses *Enter the estimated incremental Other related Admin expenses* *Please provide details in Manager's Summary*	$ -	$ -	$ - *3. LDC Assumptions and Data*	$ -	$ -	$ -	P
Total Incremental Other Operation Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	Q = O + P

AMI - Advanced Metering Infrastructure

Other - Cost or expenses not AMI but does not include stranded assets

2007 EDR Smart Meter Rate Calculation Model

Hydro One Brampton Networks Inc.

EB-2007-0541

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Sheet 3. LDC Assumptions and Data

Assumptions:

1. Planned meter installations occur evenly through the year.
2. Year assumed January to December
3. Amortization is straight line and has half year rule applied in first year

2006 EDR Data Information

Deemed Debt (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell C 18)	55%	*4. Smart Meter Rate Calc*
Deemed Equity (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell C 19)	45%	*4. Smart Meter Rate Calc*
Weighted Debt Rate (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell C 25)	6.95%	*4. Smart Meter Rate Calc*
Proposed ROE (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell E 32)	9.00%	*4. Smart Meter Rate Calc*
Weighted Average Cost of Capital	7.87%	

2006 EDR Total Metered Customers

Sum of Residential, General Service, and Large User *from 2006 EDR Sheet "7-1 ALLOCATION - Base Rev. Req." Cells H16 thru H93*	110,437	*4. Smart Meter Rate Calc*

2006 EDR Tax Rate

Corporate Income Tax Rate *(from 2006 PILs Sheet "Test Year PILs,Tax Provision" Cell D 14)*	36.12%	*5. PILs*

Capital Data:

	2006	2007	2008	2009	2010	Total
Smart meter including installation ($125.33 times Planned Meters Installed)	$ 626,650	$ 3,759,900	$ 4,386,550	$ 4,386,550	$ 3,383,910	$ 16,543,560
Computer Hardware Costs *2. Smart Meter Data; AMI (F) plus Other (I)*	$ -	$ 200,000	$ -	$ -	$ -	$ 200,000
Computer Software Costs *2. Smart Meter Data; AMI (G) plus Other (J)*	$ -	$ 300,000	$ -	$ -	$ -	$ 300,000
Total Computer Costs *2. Smart Meter Data; AMI (H) plus Other (K)*	$ 626,650	$ 4,259,900	$ 4,386,550	$ 4,386,550	$ 3,383,910	$ 17,043,560

6. SM Avg Net Fixed Assets &UCC

LDC Amortization Policy:

Smart Meter Amortization Rate *Enter Amortization Policy*	15	Years	*6. SM Avg Net Fixed Assets &UCC*
Computer Hardware Amortization Rate *Enter Amortization Policy*	5	Years	*6. SM Avg Net Fixed Assets &UCC*
Computer Software Amortization Rate *Enter Amortization Policy*	3	Years	*6. SM Avg Net Fixed Assets &UCC*

Operating Expense Data:

	2006	2007	2008	2009	2010	Total
Incremental O&M Expenses *2. Smart Meter Data; AMI (L) plus Other (O)*	$ -	$ -	$ -	$ -	$ -	$ -
Incremental Admin Expenses *2. Smart Meter Data; AMI (M) plus Other (P)*	$ 54,000	$ 410,000	$ 670,000	$ 860,000	$ 1,050,000	$ 3,044,000
Total Incremental Operating Expense *2. Smart Meter Data; AMI (N) plus Other (Q)*	$ 54,000	$ 410,000	$ 670,000	$ 860,000	$ 1,050,000	$ 3,044,000

4. Smart Meter Rate Calc

Per Meter Cost Split:

	Per Meter	Installed	Investment	% of Invest
Smart meter including installation	$ 125.33	132,000	$ 16,543,560	82%
Computer Hardware Costs	$ 1.52	132,000	$ 200,000	0%
Computer Software Costs	$ 2.27	132,000	$ 300,000	0%
Smart meter incremental operating expenses	$ 23.06	132,000	$ 3,044,000	0%
Total Smart Meter Capital Costs per meter	$ 152.18		$ 20,087,560	82%

2007 EDR Smart Meter Rate Calculation Model
Hydro One Brampton Networks Inc.
EB-2007-0541
09-Feb,2007
Sheet 4. Smart Meter Rate Calc

Ontario

Smart Meter Rate Calculation

	2007				
Average Asset Values					
Net Fixed Assets Smart Meters *(6. SM Avg Net Fixed Assets &UCC)*	$ 2,402,158				
Net Fixed Assets Computer Hardware *(6. SM Avg Net Fixed Assets &UCC)*	$ 90,000				
Net Fixed Assets Computer Software *(6. SM Avg Net Fixed Assets &UCC)*	$ 125,000				
Total Net Fixed Assets	$ 2,617,158	$ 2,617,158			*A*
Working Capital					
Operation Expense	$ 410,000				
15 % Working Capital	$ 61,500	$ 61,500			*B*
Smart Meters included in Rate Base		$ 2,678,658			*C = A + B*
Return on Rate Base					
Deemed Debt *(3. LDC Assumptions and Data)*	55.0%	$ 1,473,262			*D = C * Deemed Debt*
Deemed Equity *(3. LDC Assumptions and Data)*	45.0%	$ 1,205,396			*E = C * Deemed Equity*
		$ 2,678,658			
Weighted Debt Rate *(3. LDC Assumptions and Data)*	7.0%	$ 102,392			*F = D * Weighted Debt Rate*
Proposed ROE *(3. LDC Assumptions and Data)*	9.0%	$ 108,486			*G = E * Proposed ROE*
Return on Rate Base		$ 210,877	$ 210,877		*H = F + G*
Operating Expenses					
Incremental Operating Expenses *(3. LDC Assumptions and Data)*			$ 410,000		*I*
Amortization Expenses					
Amortization Expenses - Smart Meters *(6. SM Avg Net Fixed Assets &UCC)*		$ 167,107			
Amortization Expenses - Computer Hardware *(6. SM Avg Net Fixed Assets &UCC)*		$ 20,000			
Amortization Expenses - Computer Software *(6. SM Avg Net Fixed Assets &UCC)*		$ 50,000			
Total Amortization Expenses			$ 237,107	*5. PILs*	*J*
Revenue Requirement Before PILs			$ 857,984		*K = H + I + J*
Calculation of Taxable Income					
Incremental Operating Expenses			-$ 410,000		*I*
Depreciation Expenses			-$ 237,107		*J*
Interest Expense			-$ 102,392		*F*
Taxable Income For PILs			$ 108,486	*5. PILs*	*L = K - I - J - F*
Grossed up PILs *(5. PILs)*			$ 33,433		*M*
Revenue Requirement Before PILs			$ 857,984		*K*
Grossed up PILs *(5. PILs)*			$ 33,433		*M*
Revenue Requirement for Smart Meters			**$ 891,417**		*N = K + M*
2007 Smart Meter Rate Adder					
Revenue Requirement for Smart Meters			$ 891,417		*N*
2006 EDR Total Metered Customers *(3. LDC Assumptions and Data)*			110,437		*O = 2006 EDR Total Metered Customers*
Annualized amount required per metered customer			$ 8.07		*P = N / O*
Number of months in year			12		*Q*
2007 Smart Meter Rate Adder			**$ 0.67**	Enter this amount in the 2007 IRM Model sheet "4. 2006 Smart Meter Information" in cells F 17 thru F 32 (as required)	*R = P / Q*

2007 EDR Smart Meter Rate Calculation Model
Hydro One Brampton Networks Inc.
EB-2007-0541
09-Feb,2007
Sheet 5. PILs

PILs Calculation

INCOME TAX	
Net Income *(4. Smart Meter Rate Calc)*	$ 108,486
Amortization *(4. Smart Meter Rate Calc)*	$ 237,107
CCA - Class 47 (8%) Smart Meters *(6. SM Avg Net Fixed Assets &UCC)*	-$ 198,523
CCA - Class 45 (45%) Computers *(6. SM Avg Net Fixed Assets &UCC)*	-$ 112,500
Change in taxable income	$ 34,570
Tax Rate *(3. LDC Assumptions and Data)*	36.12%
Income Taxes Payable	$ 12,487
ONTARIO CAPITAL TAX	
Smart Meters *(6. SM Avg Net Fixed Assets &UCC)*	$ 4,198,555
Computer Hardware *(6. SM Avg Net Fixed Assets &UCC)*	$ 180,000
Computer Software *(6. SM Avg Net Fixed Assets &UCC)*	$ 250,000
Rate Base	$ 4,628,555
Less: Exemption	$ -
Deemed Taxable Capital	$ 4,628,555
Ontario Capital Tax Rate	0.300%
Net Amount (Taxable Capital x Rate)	$ 13,886

Gross Up

	PILs Payable	Gross Up	Grossed Up PILs	
Change in Income Taxes Payable	$ 12,487	36.12%	$ 19,547	
Change in OCT	$ 13,886		$ 13,886	
PIL's	$ 26,372		**$ 33,433**	*4. Smart Meter Rate Calc*

2007 EDR Smart Meter Rate Calculation Model
Hydro One Brampton Networks Inc.
EB-2007-0541
09-Feb,2007
Sheet 6. SM Avg Net Fixed Assets &UCC

Smart Meter Average Net Fixed Assets

Net Fixed Assets - Smart Meters

	2006	2007	
Opening Capital Investment	$ -	$ 626,650	
Capital Investment Year 1 *(3. LDC Assumptions and Data)*	$ 626,650		
Capital Investment Year 2 *(3. LDC Assumptions and Data)*		$ 3,759,900	
Closing Capital Investment	$ 626,650	$ 4,386,550	
Opening Accumulated Amortization	$ -	$ 20,888	
Amortization Year 1 (15 Years Straight Line)	$ 20,888	$ 41,777	
Amortization Year 2 (15 Years Straight Line)		$ 125,330	
Closing Accumulated Amortization	$ 20,888	$ 187,995	
Opening Net Fixed Assets	$ -	$ 605,762	
Closing Net Fixed Assets	$ 605,762	$ 4,198,555	*5. PILs*
Average Net Fixed Assets	$ 302,881	$ 2,402,158	*4. Smart Meter Rate Calc*

Net Fixed Assets - Computer Hardware

	2006	2007	
Opening Capital Investment	$ -	$ -	
Capital Investment Year 1 *(3. LDC Assumptions and Data)*	$ -		
Capital Investment Year 2 *(3. LDC Assumptions and Data)*		$ 200,000	
Closing Capital Investment	$ -	$ 200,000	
Opening Accumulated Amortization	$ -	$ -	
Amortization Year 1 (5 Years Straight Line)	$ -	$ -	
Amortization Year 2 (5 Years Straight Line)		$ 20,000	
Closing Accumulated Amortization	$ -	$ 20,000	
Opening Net Fixed Assets	$ -	$ -	
Closing Net Fixed Assets	$ -	$ 180,000	*5. PILs*
Average Net Fixed Assets	$ -	$ 90,000	*4. Smart Meter Rate Calc*

Net Fixed Assets - Computer Software

	2006	2007	
Opening Capital Investment	$ -	$ -	
Capital Investment Year 1 *(3. LDC Assumptions and Data)*	$ -		
Capital Investment Year 2 *(3. LDC Assumptions and Data)*		$ 300,000	
Closing Capital Investment	$ -	$ 300,000	
Opening Accumulated Amortization	$ -	$ -	
Amortization Year 1 (3 Years Straight Line)	$ -	$ -	
Amortization Year 2 (3 Years Straight Line)		$ 50,000	
Closing Accumulated Amortization	$ -	$ 50,000	
Opening Net Fixed Assets	$ -	$ -	
Closing Net Fixed Assets	$ -	$ 250,000	*5. PILs*
Average Net Fixed Assets	$ -	$ 125,000	*4. Smart Meter Rate Calc*

Ontario

2007 EDR Smart Meter Rate Calculation Model
Hydro One Brampton Networks Inc.
EB-2007-0541
09-Feb,2007

Sheet 6. SM Avg Net Fixed Assets &UCC

For PILs Calculation

UCC - Smart Meters

CCA Class 47 (8%)	2006	2007	
Opening UCC	$ -	$ 601,584	
Capital Additions	$ 626,650	$ 3,759,900	
UCC Before Half Year Rule	$ 626,650	$ 4,361,484	
Half Year Rule (1/2 Additions - Disposals)	$ 313,325	$ 1,879,950	
Reduced UCC	$ 313,325	$ 2,481,534	
CCA Rate Class 47	8%	8%	
CCA	$ 25,066	$ 198,523	*5. PILs*
Closing UCC	$ 601,584	$ 4,162,961	

UCC - Computer Equipment

CCA Class 45 (45%)	2006	2007	
Opening UCC	$ -	$ -	
Capital Additions Hardware	$ -	$ 200,000	
Capital Additions Software	$ -	$ 300,000	
UCC Before Half Year Rule	$ -	$ 500,000	
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 250,000	
Reduced UCC	$ -	$ 250,000	
CCA Rate Class 45	45%	45%	
CCA	$ -	$ 112,500	*5. PILs*
Closing UCC	$ -	$ 387,500	

1.0 Reference: Exhibit B-1, pages 3 and 5

BCUC Staff IR #10

Q1.1 Given the required AMI Functions set out on page 40, what "innovative rate structures and competitive demand side management opportunities" will AMI permit that are not possible with current metering but will be possible without further investment in meters and the associated infrastructure?

A1.1 It is expected that the implementation of Time-of-Use (TOU) and Critical Peak Pricing (CPP) rates will not require additional investment in the selected AMI technology, but upgrades may be required to FortisBC's IT systems. The functions and features set out on page 40 of the CPCN Application (Exhibit B-1) allow for the future possibility of implementing these programs but did not include the incremental costs that may be required to implement them.

2.0 Reference: Exhibit B-1, page 4

Q2.1 The text (lines 4-12) sets out three categories of savings. Please confirm that only savings from the first category (i.e., operational savings) were included in the net present value impact on rates assessment that yielded the -0/09 % result over 25 years.

A2.1 FortisBC confirms that only savings from the first category were included in the net present value calculations.

Q2.2 What is meant by "cost effective and competitive demand side management opportunities, and new rate structures that promote energy efficiency and conservation"?

A2.2 The flexibility that AMI provides in both the type and frequency of data available to the utility will assist the Company in the design, implementation and evaluation of future DSM programs. FortisBC has not yet identified any specific programs and rate structures to promote energy efficiency and conservation. Please also refer to the response to BCUC IR No. 1 Q10.1.

Q2.3 If this AMI application is approved, when does FortisBC plan to implement these DSM opportunities and new rate structures?

A2.3 FortisBC has not established a timetable for the implementation of DSM opportunities and new rate structures, although a DSM program review is expected to be complete by the end of 2008.

Q2.4 Will FortisBC require BCUC approval before implementing these DSM opportunities and new rate structures?

A2.4 Yes, FortisBC will request approval of these DSM opportunities and new rate structures.

3.0 Reference: Exhibit B-1, page 11
BCUC Staff IR #3.1 and #5.1

Q3.1 For each of FortisBC's "rate schedules", please indicate how frequently the meters are currently read.

A3.1 Please see Table A3.1 below outlining the frequency of reading for each rate schedule:

Table A3.1: Frequency of Reading by Rate Schedule

Rate Description	Rate Schedule	Reading Frequency
Residential Service	1	Bi-Monthly
Residential Service - Time-of-Use - closed	2	Monthly
Residential Service - Time-of-Use	2A	Bi-Monthly
Residential Service - Green Power	3	Bi-Monthly
Residential Service - Time-of-Use - Green Power	4	Monthly
Small General Service	20	Bi-Monthly
General Service	21	Monthly
General Service - Secondary - Time-of-Use - closed	22	Monthly
General Service - Secondary - Time-of-Use	22A	Bi-Monthly
General Service - Primary - Time-of-Use	23	Monthly
Small General Service - Green Power	24	Monthly
General Service - Green Power	25	Monthly
General Service - Secondary - Time-of-Use - Green Power	26	Monthly
General Service - Primary - Time-of-Use – Green Power	27	Monthly
Large General Service – Primary	30	Monthly
Large General Service – Transmission	31	Monthly
Large General Service - Primary - Time-of-Use	32	Monthly
Large General Service - Transmission - Time-of-Use	33	Monthly
Large General Service - Primary - Time-of-Use - Green Power	34	Monthly
Large General Service - Transmission - Green Power	35	Monthly
Large General Service - Transmission - Time-of-Use - Green Power	36	Monthly
Wholesale Service - Primary	40	Monthly
Wholesale Service - Transmission	41	Monthly
Wholesale Service - Primary - Time-of-Use	42	Monthly
Wholesale Service - Transmission - Time-of-Use	43	Monthly
Wholesale Service - Primary - Green Power	44	Monthly
Wholesale Service - Primary - Time-of-Use - Green Power	45	Monthly
Wholesale Service - Transmission - Green Power	46	Monthly
Wholesale Service - Transmission - Time-of-Use - Green Power	47	Monthly
Lighting - All Areas	50	Un-metered
Lighting - Green Power	50	Un-metered
Irrigation and Drainage	60	Monthly
Irrigation and Drainage - Time-of-Use	61	Monthly
Irrigation and Drainage - Green Power	62	Monthly
Irrigation and Drainage - Time-of-Use - Green Power	63	Monthly

Q3.2 Page 11 makes reference to "AMI technologies". The project involves the purchase and installation of AMI-enabled meters as well as network infrastructure capable of collecting and communicating the meter reads to a central location. When reference is made to declining costs for AMI technologies, which of these aspects does the reference refer to?

A3.2 Please refer to the response to BCUC IR No. 1 Q5.1.

4.0 Reference: Exhibit B-1, page 6

Q4.1 Will the RFP cover all aspects of the project including:

- **the AMI-enabled meters,**
- **the required enhanced communication network infrastructure, and**
- **IT/System changes necessary to incorporate the metering data into the CIS?**

If not, which aspects will it include?

A4.1 The RFP will cover all of the above aspects of the AMI Project.

Q4.2 Will the RFP cover the maintenance requirements for the enhanced communications network infrastructure and the Systems required to incorporate the metering data into the CIS?

A4.2 As part of the RFP, vendors will provide maintenance requirements for the enhanced communications network infrastructure and systems used to incorporate the metering data into the CIS.

5.0 Reference: Exhibit B-1, pages 12, 29 and 44

Preamble: Pages 44-47 outline three different technology options for AMI communications.

Q5.1 Are the costs of implementing the three options reasonably comparable? If not, why not?

A5.1 Please refer to the response to BCUC IR No. 1 Q18.1.

Q5.2 Given there are three different approaches, how was the cost estimate set out on page 29 established?

A5.2 Please refer to the response to BCUC IR No. 1 Q28.1

Q5.3 What other factors (i.e., differences between these technologies) could influence FortisBC's choice besides cost?

A5.3 The other factors that will be considered in addition to cost in the RFP process include:

- Vendor Stability;
    - Financial stability;
    - Proven installations;
    - Ease of vendor relationship;
    - Utility references;
    - Manufacturing capacity; and
    - Scalability.
- Product warranties and guarantees; and
- The vendor's ability to deliver on the required functions and features listed in Table 7.1 of the CPCN Application (Exhibit B-1).

6.0 Reference: Exhibit B-1, page 14

Q6.1 Are the meter testing costs the same for the AMI-enabled meters as they are for the meters FortisBC currently uses? If not, has the difference been factored into the NPV and rate impact analysis?

A6.1 The testing costs per meter are expected to be the same as they are today. For additional information please refer to the responses to BCUC IR No. 1 Q22.2 and Q22.3.

7.0 Reference: Exhibit B-1, page 16

Q7.1 Are the maintenance costs for the AMI-enable meters higher than for FortisBC's current meters? Is so, where is this incorporated in Table 4.1.1.4?

A7.1 The maintenance costs for the meters are not expected to be any higher for AMI enabled meters as compared to the meters used today. Therefore, the maintenance costs are not included in Table 4.1.1.4.

Q7.2 What is the service life for network and IT infrastructure (see page 29) associated with the project? Are the replacement costs for this covered by the $48,000 in contingency funds for equipment replacements? If not, has the future replacement of this equipment been incorporated in the 25-year rate impact analysis?

A7.2 The service life of the network and IT infrastructure is 25 years. The expected replacement costs for the network infrastructure are contained within the $48,000 per year of "Equipment Replacements". Future support and upgrade costs for the IT infrastructure are budgeted in ongoing AMI operating expenses listed as item (ii) in Table 4.1.1.4 on page 16 of the CPCN Application (Exhibit B-1). These costs are expected to be approximately $38,000 per year.

8.0 Reference: Exhibit B-1, pages 20 and 40

Q8.1 How many time "buckets" will the AMI-enabled meters be required to be able to support (per page 20)?

A8.1 The number of "buckets" the AMI-enabled meters will be able to support will depend on the amount of memory within the meter and the frequency that readings are transmitted (daily, hourly).

Q8.2 Please clarify what is meant by the required functionality of "Hourly readings for select customer profiles" (page 40)?

A8.2 This functionality will allow FortisBC to issue a request on the AMI system to monitor hourly usage patterns of specific customers as required.

Q8.3 Will all of the "required" functions identified in Table 7.1 be mandatory requirements for parties responding to FortisBC's planned RFP? If not, what is meant by the term "required"?

A8.3 Yes, all of the "required" functions identified in Table 7.1 from the CPCN Application (Exhibit B-1) will be mandatory requirements in the RFP process.

Q8.4 Please confirm that the AMI-enabled meters FortisBC is proposing to install will be capable of supporting TOU rates (with defined pricing periods/buckets) but not hourly pricing. If this is not the case, please reconcile with the functionality requirements set out in Table 7.1.

A8.4 Confirmed.

Q8.5 How did FortisBC decide which AMI functions and features to require, and which to make optional?

A8.5 FortisBC engaged an experienced AMI consultant who identified the functional requirements that are standard with most AMI systems. The consultant also assisted in identifying areas of possible benefits for FortisBC's customers. Based on this information, FortisBC determined the savings that would be achieved from these benefits and ensured that all required functions had an associated benefit within the business case. The optional requirements were those that FortisBC feels would be beneficial but were unable to quantify in any substantive way.

9.0 Reference: Exhibit B-1, page 21

Q9.1 Please address separately whether the AMI Project is required in order to:

- **Enable the Company to target specific elements of the electrical distribution infrastructure for upgrades, and**
- **Enable the Company to target future system loss improvements.**

If AMI is required for either, please reconcile with position taken by FortisBC on this issue during the review of FortisBC's CPCN Application regarding the Substation Automation Project.

A9.1 AMI enables the analysis of actual distribution feeder losses. FortisBC expects this information will enable the Company to better target future system loss improvements.

Q9.2 The Application states that "the physical replacement of meters will provide an opportunity to identify and resolve revenue protection and metering issues". Are the meter readers who attend currently at customers' premises not already identifying revenue protection and metering issues?

A9.2 To ensure the safety and security of meter readers in the field, identifying revenue protection issues has not been defined as part of the meter reader's responsibilities. With the implementation of AMI, the majority of the meter population would be replaced over the implementation period which would allow an opportunity to identify and resolve revenue issues.

Q9.3 Please provide examples of revenue protection and metering issues that will be identified through the physical replacement of meters with AMI meters? Will these revenue protection and metering issues be any different from those that are already identified by meter readers who currently attend at customers' premises?

A9.3 Examples of revenue protection and metering issues that could be identified during the physical replacement of the meters are as follows:

Diversion Detection: Physical removal of the meter may reveal prior tampering and alert the installer to a possible power diversion.

Meter Errors: The replacement of each meter would identify any errors with the existing meters (multipliers; stopped meters; slow meters). It is sometimes difficult for a meter reader to identify stopped or slow meters because they are not able to see if the house is vacant or if the breaker is turned off. This is especially true in areas with recreational properties.

Tampered Meters: With the full replacement, any meter that has been tampered with will be replaced with a fully functional meter.

As stated in the response to BCOAPO IR No. 1 Q9.2, identifying revenue protection issues such as diversion is not part of the meter reader's responsibilities. Meter errors and tampered meters will be easier to identify with the AMI installation because the meter will be physically removed and inspected. Meter readers spend a short amount of time at each meter and therefore, these types of issues are difficult for them to identify.

10.0 Reference: Exhibit B-1, pages 22-23

Q10.1 If Remote Disconnect/Reconnect is a "future option" why is it a required functionality (per page 40)?

A10.1 FortisBC identified this requirement as "Supports Remote Disconnect / Reconnect" rather than "Includes Remote Disconnect / Reconnect" to ensure that the functionality could be added later with an additional cost. This feature is most often an add-on to existing systems with a collar that fits behind the meter. FortisBC feels that it is important that the AMI-enabled meter chosen is compatible with this device in the event that this feature is utilized in the future.

Q10.2 The functionality requirements on page 40 list as "required" a number of features that are associated with future benefits. Please provide a schedule that lists all such features and that indicates the anticipated incremental costs associated with including each at this stage. In each case, please discuss briefly the implications (e.g. significantly increased cost to include later) of not including the feature at this stage.

A10.2 The items listed as required within Table 7.1 from the CPCN Application (Exhibit B-1) are separated between those that are required as functional initially and those that are required but not to be functional during this stage of the AMI implementation. The latter category is comprised of the following functions and features:

Supports TOU pricing models: The system and meter must be able to be programmed to accommodate TOU pricing models. There is no incremental cost to include this option in the AMI system now.

Supports block pricing models: The system and meter must be able to be programmed to accommodate block pricing models. There is no incremental cost to include this option in the AMI system now.

Supports CPP pricing models: The system and meter must be able to be programmed to accommodate CPP pricing models including two-way communications with the meter. Since there are other requirements listed that also require two-way communication, there is no incremental cost to include this option in the AMI system now.

Supports load control: The system must provide future capability to upgrade the system to handle load control devices through some means. There is no incremental cost to include this option in the AMI system now.

Supports remote disconnect/reconnect: The system must be compatible with the remote disconnect/reconnect collars presently on the market. The purchase of the collars is not currently within the scope of this Project, and there is no expected incremental cost to provide this capability.

If these features were not included within the scope of the RFP now, then FortisBC would be at risk of purchasing an AMI system that could not easily be upgraded to support future initiatives which could mean a wholesale change-out of meters in the future.

Due to this level of exposure and the fact that there is no incremental cost to include these functions now, FortisBC feels it is important to include them within the scope of the RFP.

Q10.3 The Application states that AMI infrastructure would allow for a program to place load-controlling devices onto appliances in customers' premises. Could load-controlling devices be attached to appliances in customers' premises and enabled to work with meters that are currently installed?

A10.3 No, the existing meters cannot work with load controlling devices in customer appliances. However, other load control technologies exist that do not require an interface with the meter. FortisBC is not considering such technologies at this time.

11.0 Reference: Exhibit B-1, page 26, lines 1-5

Q11.1 Do municipal utilities operating within FortisBC's services territory plan to install AMI for all of their customers? If not, why not?

A11.1 FortisBC is not aware of any plans by municipal utilities other than the City of Nelson and the District of Summerland to install any type of AMI system. FortisBC understands that they above referenced utilities are currently implementing drive-by AMR systems.

Q11.2 If municipal utilities do plan to install AMI for all of their customers, when do they plan to do this?

A11.2 Please see the response to BCOAPO IR No. 1 Q11.1.

12.0 Reference: Exhibit B-1, page 26 lines 6-27 and page 27 lines 1-5

Q12.1 FortisBC states that it will continue exchanging information with other utilities, but is satisfied that the technologies and requirements proposed in this application are field-proven and consistent with other utilities' proposals. Please explain why FortisBC is satisfied that the technologies and requirements proposed in this application are field-proven and consistent with other utilities' proposals.

A12.1 FortisBC has reviewed documents from several other utilities, attended conferences on the topic of AMI, and visited other Canadian utilities currently implementing an AMI system. In addition, an expert consultant was retained to verify cost estimates and system requirements to ensure that what FortisBC is requiring is consistent with other utilities and with the industry in general.

As part of the RFP process, FortisBC will be requiring vendors to demonstrate that their technology is field-proven and that they can deliver on the functional requirements listed as "required".

Q12.2 BC Hydro has been conducting a Conservation Research Initiative since November 2006 but is studying how AMI and a variety of conservation rates will affect the consumption of electricity. Why did FortisBC not wait until BC Hydro's Conservation Research Initiative is complete before filing this application for AMI?

A12.2 FortisBC's CPCN Application and benefits do not include energy conservation as a hard benefit.

FortisBC believes it is important to implement basic AMI functions day one to ensure that customers can receive the benefits that have been committed to in the CPCN Application. Additional AMI functions such as those discussed in

Appendix C of the CPCN Application (Exhibit B-1) can be implemented after the AMI system is in place. If at that time, a DSM program is feasible and in the best interest of FortisBC customers, all related information including any studies done by Canadian utilities such as BC Hydro would be reviewed.

As part of the RFP process, FortisBC will be reviewing the vendor's future ability to provide these functions after the implementation of AMI is complete.

Q12.3 Why has FortisBC decided not to conduct a research project similar to BC Hydro's Conservation Research Initiative in order to study how AMI and a variety of conservation rates will affect the consumption of electricity in FortisBC's service territory?

A12.3 Please refer to the response to BCOAPO IR No. 1 Q12.2.

Q12.4 How will FortisBC's proposed AMI system differ from the AMI technology that is being implemented by FortisAlberta?

A12.4 Until FortisBC has completed the RFP process and an AMI technology is chosen, it is unknown how FortisBC technology will differ from that which is being implemented by FortisAlberta.

Q12.5 FortisAlberta successfully deployed 26,000 automated meters as part of a pilot program. Why is FortisBC not conducting an AMI pilot program before applying to implement AMI throughout its service territory?

A12.5 Pilot programs are specifically designed to ensure that a given technology works as designed and is suited for the utility's service area. FortisBC feels that it can achieve the same results through a thorough investigation of the vendors including installation visits, learning from the results of other utilities' pilots, and implementing the AMI system in a phased, geographical fashion.

13.0 Reference: Exhibit B-1, pages 34-35

Q13.1 Is FortisBC aware of any pending/potential changes in accounting practice (particularly as it applied to rate-regulated operations) that would limit its ability to amortize the stranded meters over a longer period of time?

A13.1 Under existing Canadian Generally Accepted Accounting Principles (GAAP), a unit of property, plant and equipment, such as the stranded meters, is depreciated over its useful life which is the period of time for which an asset "is expected to contribute directly or indirectly to the future cash flows of an enterprise." The useful life of property, plant and equipment is normally the shortest of its physical, technological, commercial and legal life. If a significant technological change arises, such as the implementation of AMI, this is likely an indicator of impairment and the write-down of the carrying value would be booked through earnings for a non-rate regulated entity.

If an order is provided by the Commission to defer and amortize the write-down to mitigate the impact on customers' rates, then this deferral amount is permitted to be recorded as a regulatory asset for rate-regulated entities under Canadian GAAP.

However in 2011 it is expected that Canadian public accountable enterprises, which include rate regulated enterprises, will adopt International Financial Reporting Standards (IFRS). IFRS does not specifically address rate-regulated operations but there is the possibility that certain rate-regulated assets previously permitted under Canadian GAAP may meet the criteria of intangible assets under the existing IFRS framework. Canadian rate-regulated utilities are cooperating with the Canadian Institute of Chartered Accountants to obtain further clarification from the International Accounting Standards Board on the future accounting treatment of rate-regulated assets.

14.0 Reference: Exhibit B-1, page 38, lines 1 – 21

Q14.1 What are the “other AMI benefits” that customers will be able to take advantage of under a two-year deployment?

A14.1 The benefits discussed in this section refers to the all of the benefits the AMI project provides. These benefits are outlined in detail in Section 4.1 of the CPCN Application (Exhibit B-1).

15.0 Reference: Exhibit B-1, page 39, lines 23 – 26

Q15.1 How many “major AMI vendors” can provide the AMI technology that FortisBC is proposing?

A15.1 Please refer to the response in Wait IR No. 1 Q9.

16.0 Reference: Exhibit B-1, page 42, lines 2 - 17

Q16.1 Why does FortisBC believe that AMI technologies, once implemented, are highly reliable?

A16.1 FortisBC believes that AMI technologies, once implemented, are highly reliable due to the increased system visibility and the constant stream of data transmitted between the meters and the AMI system. Issues can be identified and corrected quickly. In addition, a number of utilities in North America are adopting AMI technologies and so these technologies have been field-tested and improved over the last several years.

As part of the RFP evaluation process, FortisBC will be examining the vendors’ technologies to determine both the reliability and the number of endpoints currently operating within the field. As a result, FortisBC will only consider implementing technologies that have demonstrated a high degree of reliability.

Q16.2 Are internal memory capabilities part of FortisBC's required AMI functions and features? If not, why not?

A16.2 Yes, internal memory of at least thirty days of readings (assuming daily readings) will be required as part of the RFP.

17.0 Reference: Exhibit B-1, page 43, lines 1 - 16

Q17.1 Please provide examples of how the three AMI solutions described in this Application have been thoroughly field-tested.

A17.1 FortisBC is aware of several successful field-tested implementations of RF and PLC-based AMI technologies, including the Chatham-Kent Hydro (RF) and FortisAlberta (PLC) implementations. Please also see the response to BCOAPO IR No. 1 Q12.1.

I kindly ask the Applicant to inform for each metering option:

Q1 please provide specifications about the meter reading device with re:

- **a brand/make of reader,**
- **b when patented**
- **c please provide patent #,**
- **d actual patent paper's claim and description**
- **e where manufactured and distributed by whom**

A1 This information is not available until such time that an AMI technology solution is selected through the RFP process. However, one of the requirements listed in Table 7.1 in the CPCN Application (Exhibit B-1), is that the selected AMI technology provide the ability to work with several meter brands and that the meters must be compatible with Measurement Canada regulations.

Q2 please provide several pictures (from different site of device)

A2 This information is not available until such time that a vendor is chosen through the RFP process.

Q3 please provide pictures of typical mounting locations and provide distance from ground level

A3 The mounting locations of the AMI meters will not generally change from existing locations, but if they do, the installations will adhere to the standards found in the British Columbia Service and Metering Guide which may be viewed at: http://www.fortisbc.com/downloads/about_us/projects/BC%20Service%20and%20Metering%20Guide-April-07.pdf.

Q4 please state minimum possible usage period without replacement

A4 Please refer to the response to BCUC IR No. 1 Q29.1

Q5 all frequencies range applied (also meaning whether each individual ratepayer meter will have different frequency/ies)

A5 This information is not available until such time that a vendor is chosen through the RFP process. Some of the frequencies used by different vendors are shown in the response to Karow IR No. 1 Q13.

Q6 interval of transmitted frequencies: state all the intervals and duration of transmissions day round and year round

A6 This information is not available until such time that a vendor is chosen through the RFP process.

Q7 direction of transmission: please state area of transmitting and which area is not being radiated

A7 This information is not available until such time that an AMI technology solution is chosen through the RFP process.

Q8 strength: please state strength of transmitted RF and whether strength of individual ratepayer's meter can be adjusted (lowered)

A8 This information is not available until such time that an AMI technology solution is chosen through the RFP process. If an RF AMI technology solution is selected, the RF transmission strength of the meter will not be adjustable by customers. All metering technologies under consideration during the RFP process must be compliant with all applicable regulations governing RF emitting devices.

Q9 please state the power usage of the new meter itself per day and year, and whether the power usage will appear separately on the power bill

A9 By design, any consumption for the operation of the AMI meter is not reflected in the customer's usage. The precise power usage of the AMI meters will not be available until such time that an AMI technology is selected through the RFP process.

Q10 please state of all possible other RF frequencies occurring in the distribution and service drop system other than caused by the actual meter reading

A10 FortisBC does not use radio frequency (RF) equipment for communications on the distribution system. The only RF signals that might be present on distribution feeders would be induced by nearby signal radiators such as radio or television transmitters.

Q11 please state whether any of these (section 11) or other foreign frequencies could have an adverse impact of any nature on the meter reading system, if so, please state in details the impacts.

A11 Interference and data corruption is an expected occurrence in all communications systems. AMI communications equipment is designed to filter and reject foreign interference. Received data is validated by the use of error correction algorithms to ensure data is received correctly prior to acceptance by the system.

Q12 Please state whether any of the metering (data sending, data demanding) system's frequency can enter and be received and transmitted/ transferred via house wiring, gas and water house-pipe system

A12 While technically it is possible for the radio frequency (RF) signal from AMI to be received by the house wiring and gas and water heat-pipe system, the signal levels are going to be of extremely small magnitude. AMI transmitters typically operate at a very low average power of a few hundredths to a few tenths of a watt, with a maximum of 1 watt in very short bursts. This signal is then strongly reduced by the house walls and shielding on the house wires and pipes and the distance from the AMI transmitter and pipes and wires. Moreover, there are already multiple sources of RF already present in residential areas. These devices, which operate at similar frequencies and power levels, include cell phones, cordless phones, WiFi networks, and AMI / AMR systems for water and gas metering applications.

Q13 Please state whether there are other means than wireless meter readings, i.e. via land-lined telephone/ cable system to a central reader office with a multiplexor system

A13 Technology options available for the Local Area Network (LAN) portion of the AMI system (between the meter and the central collection point) are:

- Spread Spectrum (900 MHz, 2.4 GHz, 802.11b, Zigbee);
- Licensed frequencies (928 MHz, 450 MHz, 220 MHz); and
- Power line carrier (PLC).

Technology options available for the Wide Area Network (WAN) portion of the AMI system (between the central collection point and the office) are:

- Plain old telephone service (POTS);
- Fiber;
- Microwave;
- Wimax;
- Pagenet / Supernet;

- T1 line;
- Interexchange Radio Transmission Technologies (IXRTT); and
- General packet radio service (GPRS).

Q14 please state whether meter reader could remotely be controlled, i.e. artificially increase the usage than actually power used. If not, please state how this is not possible

A14 The meter only records actual consumption used and will be under seal and within Measurement Canada regulation guidelines. The meter itself could not be remotely controlled to increase or decrease the amount of power measured. FortisBC has included within the scope of the RFP a requirement for secure encryption of the meter data file to prevent unauthorized access and/or modification of the data when being transmitted from the meter to the collector station.

Q15 please state whether FortisBC is aware of any already in any other country existing systems that are being used for sending utility usage data over telephone lines, if so please state country and detailed specs about that system

A15 FortisBC is not aware if other countries are using a POTS line to transmit AMI data but is aware that this is an option for the WAN portion of the AMI solution.

Q16 Please state whether there are any meters in FortisBC service area, that will <u>not</u> be fitted with the new AMI system. If so, please state reason why.

A16 Meters currently being read with the MV90 system (primarily large industrial accounts) will not be replaced with AMI enabled meters. The MV90 system functions similarly to an AMI system while the cost to replace the MV90 meters is significant with no operational gain.

Q17 Please state, if on special individual customer's demand the conventional metering system not to be changed over to the new AMI system, under what conditions may FortisBC allow so.

A17 No, the installation of AMI-enabled meters will not be optional. Allowing customers to remain on the legacy system would increase the cost to service those customers and limit the benefits offered by AMI.

Q18 Please comment on the attached paper FortisBC"s position, and please state whether FortisBC can guarantee that no corrosion whatsoever in privately owned building will be caused via the applied meter data transmitting frequencies.

A18 There is no scientifically accepted theory of corrosion for such low levels of high frequency RF fields. The only plausible mechanism by which low level of RF energy could increase corrosion rates is by increasing the temperature of the pipes, which would accelerate corrosion from other sources that would necessarily need to be present; RF energy by itself cannot cause corrosion. The emitted power from an AMI system, however, is too low to appreciably increase the temperature of the pipes, wires, and other structures in the house. The effects of water and house temperatures and solar radiation greatly overwhelm any temperature change that could be attributed to an AMI system. Again, as indicated in the response to Karow IR No. 1 Q12, there are already multiple sources of RF at similar frequencies and power levels already present in the residential areas.

The conference presentation by Michrowski referenced in the question focuses primarily on power frequency currents, not RF, and does not indicate that RF causes corrosion, just that it can enter through the electric power transmission/distribution systems and grounding wires. Moreover, the attached paper does not even propose how any RF electromagnetic fields would induce corrosion in the water pipes. In fact, RF electromagnetic waves have been proposed as a method for continuous monitoring of corrosion due to other causes.

Q19 Please indicate whether any shielding of RF frequencies in /for any direction is provided, if so please give details.

A19 Please refer to the response to Karow IR No. 1 Q2.

Project No. 3698493: Advanced Metering Infrastructure (AMI) Project
Requestor Name: Mr. Alan Wait
Information Request No: 1
To: FortisBC Inc.
Request Date: February 5, 2008
Response Date: February 26, 2008

Q1 How often do present meter readers notice and report problems with the FortisBC infrastructure as a result of their rounds?

A1 FortisBC does not track the frequency of meter reader reported problems with the FortisBC infrastructure.

Q2 Will there be more visual surveillance required of the system by other FortisBC personnel after the meter readers are no longer making rounds?

A2 FortisBC meter readers normally inspect only the meters themselves. An AMI implementation will permit remote monitoring of the state of the meters and the communication infrastructure. Therefore, it is not expected that there will be an increased need for additional visual surveillance by FortisBC personnel.

Q3 Please provide the per unit new costs of both the existing meters and the new AMI meters for residential, and some common commercial size meters in the FortisBC system.

A3 The cost of an existing residential meter is approximately $31.00 per meter. FortisBC feels that releasing detail in regards to the AMI cost estimate would jeopardize the RFP process and prevent the Company from obtaining the most competitive pricing available. However, FortisBC will provide this information in confidence to the Commission, if requested.

Q4 Please confirm if correct, that the new AMI meters can be read the same as the existing meters with the same equipment an in the same time when they are not connected to communications equipment. If not, explain.

A4 Confirmed.

Q5 What percentage of the existing meters is FortisBC presently exchanging and replacing annually?

A5 Currently, FortisBC is exchanging approximately 3 percent of the meter population annually.

Q6 How many new meters are being added to the system annually?

A6 Please refer to the response to BCUC IR No. 1 Q17.2

Q7 P.15, L.8; Are these soft readings for disconnects and connects presently covered in additional charges to the normal monthly billing?

A7 Yes, under Rate Schedule 80 of FortisBC's Electric Tariff, the present cost of a disconnection and reconnection of service involving a meter reading is $27.00. If the account is transferred and that transfer does not involve a meter reading, the cost is $6.00.

Q8 P.18, L.16; Will the AMI computer program allow the operators to key in a meter read ahead of time to automatically read the meter when a customer in closing or opening an account?

A8 The AMI system is required to provide readings for each meter on a daily basis. Therefore, it is expected that readings will be available for the CIS system to use when calculating a final or opening bill based on the move in/out date. In addition, the system will have the ability to obtain scheduled readings on meters at different times as well as on-demand readings based on a request from an operator.

Q9 P.39, 7.1; Please name the anticipated vendors capable of supplying each of the PLC and RF technology meters and communications equipment.

A9 The following is a non-exhaustive list of AMI technology and service vendors capable of supplying AMI meters and communications equipment.

Arch Rock
Cellnet Hunt
Comverge
CURRENT
Echelon
Elster Integrated Solutions
eMeter
ESCO Technologies
Gestalt
Honeywell
i-conserve, LLC
ista
Itron Inc.
Landis+Gyr
muNet, Inc.
Neptune Technology Group
Nexus Energy Software
Schneider Electric
Sensus Metering
Silver Spring Networks
Tantalus
Tech Data Solutions
Trilliant Networks
TWACS by DCSI
UTILITYnet
Zensys
ZigBee Alliance

Q10 Does the equipment that these prospective bidding companies have, operate on a common platform such that meters and communications equipment are interchangeable between suppliers in the future or will the FortisBC system be locked into the equipment from the successful bidders in the future?

A10 Some vendors have proprietary communications protocols while others do not. This item will be considered within the scope of the RFP to ensure FortisBC has sufficient future flexibility. In addition, one of the requirements listed in Table 7.1 in the CPCN Application (Exhibit B-1) is that the system be able to work with multiple meter manufacturers. FortisBC believes that it is important to retain a choice of meters available to ensure flexibility and the best possible pricing in the future.

Q11 P.45; L6-8 Please quantify the data transmission delays to be expected from FortisBC's busiest substation, if it used only PLC technology. Specifically what type of information requests would cause problems? Is this technology improving on a yearly basis?

A11 FortisBC does not have sufficient information to estimate the delays, if any, that will be experienced in sending data to and from the Company's busiest substation. This information can be better estimated once a technology has been chosen and the network design plan has been completed. However, FortisBC has spoken to other utilities that have implemented PLC technologies and they are reporting delays of anywhere between 1 and 12 hours. The delays are typically related to issues with bandwidth. Therefore, the more frequently meters are read, how many components are being read (voltage, demand) and the more communication there is on the network, the more possibility there is for a delay. Regardless of any delay in transmission, the date and timestamp on the reading will always reflect the date and time the reading was taken, not the time it was delivered to the central computer. PLC vendors are actively attempting to improve this aspect of the technology.

Q12 Please provide the depreciation rate for each of: meters, computer hardware, computer software, and communications equipment.

A12 Please refer to the response to BCUC IR No. 1 Q15.1.

Q13 Does the AMI meter fit straight into the existing meter receptacles?

A13 AMI meters are designed to fit straight into the existing meter receptacle. However, since some AMI meters are either the same size or slightly deeper than the current meters, it is possible that some installations may have clearance issues. In situations where there are clearance issues, FortisBC will work with the customer to minimize any inconvenience associated with the installation.

Q14 Provide an overview of the AMI system which is costed in App. B, with: the number of FortisBC substations in the system by 2010, the number of PLC stations planned, the number of RF stations planned.

A14 The infrastructure estimated within the CPCN Application consists of the following:

- 53 substations requiring communications infrastructure; and
- 17 towers with various repeater and collector stations.

Q15 Please provide the expected cost of a PLC station and an RF station.

A15 Please refer to the response to BCUC IR No. 1 Q3.1.

Q16 Would any extra costs or savings over the years show up in the basic charge or in the energy charge?

A16 The annual rate impact described in Figure 6.6 on page 37 of the CPCN Application (Exhibit B-1) assumes a general rate increase to all billing components. Any changes to the rate structures would be the subject of a rate design application.

Q17 What has been the cost trend of AMI meters over the last five years? Have the reporting and interactive capabilities been improving significantly over the last five years? And specifically PLC reporting?

A17 Please refer to the response to BCUC IR No. 1 Q5.1.

Q18 The AMI meters will come on stream in a staggered fashion through 2009 and 2010. Will FortisBC reduce the O&M target amount by the savings in meter reading costs for the partial years reduction in staff?

A18 Please refer to the response to BCUC IR No. 1 Q1.1.

Q19 Are there going to be severance costs associated with the meter reading staff? If so, how much, and where is that shown?

A19 FortisBC does not anticipate any costs associated with the labour force reduction. Please refer to the response to BCUC IR No. 1 Q21.3.

Q20 How many years would it take to reach a break even point for ratepayers, if calculated in constant dollars, making the AMI change and considering only meter reading?

A20 In constant 2011 dollars and factoring in only customer growth and meter reading cost savings (labour, vehicles and staff expenses), the break even point for ratepayers would be 23 years.

Q21 Please show the calculation of the Project NPV of –0.09% in App. B.

A21 The Project impact of -0.09 percent is calculated by dividing the NPV of the revenue requirements (line 5 below) for the Project by the NPV of total revenue requirements for the Company (line 6 below).

= (2,851)/3,042,076 = (0.09%)

Table A21: Revenue Requirements/Rate Impact

	Revenue Requirements (NPV)	**($000s)**
1	Operating Expense (Incremental)	(26,206)
2	Depreciation Expense	10,256
3	Carrying Costs	13,335
4	Income Tax	(235)
5	Total Revenue Requirement for Project	(2,851)
	Rate Impact (NPV)	
6	Forecast Revenue Requirements	3,042,076
7	**NPV of Project / Total Revenue Requirements**	**-0.09%**

Q22 Please justify the use of the 10% discount rate rather than something much closer to the inflation rate, considering that the vast majority of FortisBC customers are individuals and amounts saved or cost is in almost all cases are quite small per account. Please comment on the differences; that individuals operate on an after tax basis, business costs are before taxes, while business savings are reduced by taxes and how this is accounted for in the final discount figure of 10%.

A22 The discount rate is based on a real discount rate of 8.0 percent plus inflation of 2.0 percent. FortisBC has used a real discount rate of 8.0 percent as a base case in evaluating its capital expenditures for a number of years.

In its Reasons for Decision with regard to BC Hydro's 2006 Integrated Electricity Plan and 2006 Long Term Acquisition Plan, the Commission examined the question of what is the appropriate discount rate for BC Hydro to use when calculating the economic and rate impact analysis of major projects. The Commission concluded that:

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

and that:

"the Commission Panel finds no justification for the use of different discount rates for the economic analysis and the ratepayer impact analysis… However, the Commission Panel does continue to see value in sensitivity analyses around a single discount rate."

FortisBC's after-tax weighted average cost of capital has been set for rate setting purposes at 6.3 percent for 2008 indicating a nominal discount rate of 8.3 percent assuming inflation of 2.0 percent. However, interest rates are at a historical low in terms of a normal business cycle and the Company considers the use of a 10.0 percent nominal discount rate to be within a reasonable range and that sensitivity analysis around the discount rate would provide an adequate assessment of discount rate risk.