December 16, 2011

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: Smart Meter Prudence Review – Innisfil Hydro Distribution Systems Limited ED-2002-0520

Innisfil Hydro Distribution Systems Limited (IHDSL) respectfully submits to the Ontario Energy Board (the "Board") it's Smart Meter Prudence Review application. IHDSL is seeking recovery of smart meter capital and OM&A costs associated with the smart meter project for an effective date of May1, 2012.

The Smart Meter Prudence Review was prepared following the G-2011-0001 Guideline Smart Meter Funding and Cost Recovery – Final Disposition and includes the following components within the application,

- IHDSL Smart Meter Prudence Review Summary
- Completed V2.17 Smart Meter Model required by the Board
- Supporting documentation citied within the Smart Meter Prudence Review application

Further to the Board's RESS filing guidelines, an electronic copy of IHDSL's Smart Meter Prudence Review application will be submitted through the OEB e-Filing Services. We would be pleased to provide any further information or details that you may require relative to this application.

Yours respectfully**,**

Brenda L Pinke
Regulatory/CDM Officer
brendap@innifilhydro.com
(705) 431-6870 Ext 262

.cc Laurie Ann Cooledge, CMA, CPA

Innisfil Hydro Distribution Systems Limited

License – ED-2002-0520

Smart Meter Prudence Review Application

1. Introduction:

This application is being filed by Innisfil Hydro Distribution Systems Limited (IHDSL) for smart meter cost recovery for the implementation of smart meters in IHDSL service territory. The cost recovery is based on actual costs incurred to December 31, 2011 and forecasted costs to December 31, 2012.

IHDSL is not required to file a Cost of Service Application until 2013, thus IHDSL is filing this stand-alone Smart Meter Prudence Review application to specifically request the following rider(s) to be effective May 1, 2012:

IHDSL is specifically requesting the following:

1. **Smart Meter Disposition Rate Rider (SMDR) –** An actual cost recovery rate rider of $0.29 per Residential customer per month and $0.96 per General Service less than 50 kW customer per month for two years per metered customer (May 1, 2012 to April 30, 2014). This rate rider reflects the Net Deferred Revenue Requirement of $117,444 being the difference between the Deferred Incremental Revenue Requirement from 2006 to December 31, 2011 and the SMFA Revenues collected from 2006 to April 30, 2012.

   IHDSL specifically requested a 2 year disposition for both the SMDR Rate Rider (within this application) and the Group 1 DVA account variances in the 2012 IRM application EB-2011-0176. The 2 year disposition timeframe will assist in mitigating the overall rate impact of the SMIRR.

2. **Smart Meter Incremental Revenue Requirement Rate Rider (SMIRR) –** A forecasted cost recovery rate rider of $0.95 per Residential customer per month and $3.12 per General Service less than 50 kW customer per month. The SMIRR rate rider reflects the incremental revenue requirement related to smart meter costs to be incurred from January 1, 2012 to December 31, 2012.

IHDSL is not asking for recovery of the stranded meter costs but continues to include these in rate base for rate-making purposes, as recommended by the Board in its Decision with Reasons in the Smart Meter Combined Proceeding (EB-2007-0063). The issue of stranded meter costs will be addressed in IHDSL's 2013 Cost of Service Application.

Allocation determination of the SMDR and SMIRR riders is addressed in Section 17 of this application.

Calculation of Disposition Rate Rider by Class (SMDR)

	Residential	GS<50	Total Smart Meter Customers
Total Smart Meter True-up for Disposition	$ 96,663	$ 20,780	$ 117,443
Number of Customers	13,819	902	14,721
Total Monthly Disposition Rate Rider	**$ 0.29**	**$ 0.96**	**$ 0.33**

Calculation of Incremental Revenue Requirement Rate Rider by Class (SMIRR)

	Residential	GS<50	Total Smart Meter Customers
Total Smart Meter True-up for Disposition	$ 314,053	$ 67,515	$ 381,568
Number of Customers	13,819	902	14,721
Total Monthly Disposition Rate Rider	**$ 0.95**	**$ 3.12**	**$ 2.16**

2. Collaboration of LDCs:

IHDSL participated with LDCs within the Cornerstone Hydro Electric Concepts Association (CHEC) to implement smart meters in a cost effective manner. The collaborative initiative assisted LDCs in the development of project plans, RFPs and contract evaluations. As part of the collaborative effort CHEC LDCs entered into a professional services agreement with Util-Assist Inc., an Ontario consulting firm specializing in metering solutions and technologies, to assist with the development of the project plan, RFPs, evaluations, award of contract, project monitoring, problem solving and reporting. The cost benefit of the services agreement was reviewed and renewed in January of 2010. Review documents are included in Addendum 7 as confidential material.

CHEC is a not-for-profit member owned organization that provides value added services to their Local Distribution Companies (LDC) members. CHEC strives to reduce LDC costs through sharing of knowledge and information as well as providing savings through joint purchasing of goods and services with its members.

The twelve LDCs which form CHEC represent a customer base of approximately 100,000 customers. The existing members in CHEC include the following LDCs:

Centre Wellington Hydro
COLLUS Power
Innisfil Hydro
Lakefront Utilities
Lakeland Power Distribution
Midland Power Utility
Orangeville Hydro
Parry Sound Power
Rideau St. Lawrence Distribution
Wasaga Distribution
Wellington North Power
West Coast Huron Energy.

Cornerstone Hydro Electric Concepts Association (CHEC) is an incorporated body that is governed by a Board of Directors. The Board of Directors and Executive are voluntary positions from staff of the member Local Distribution Companies (collectively, "LDCs" or "Member LDC's"). CHEC's vision is "to be recognized as the premier LDC Cooperative in the province, by meeting or exceeding member expectations through the sharing of services, opportunities, knowledge and resources." CHEC is built on sharing between LDCs through committees, staff and consultant positions, shared documents, specific working groups, combined projects and informal communications between members and staff.

The MDMR Project represents one of these combine projects where LDCs working together achieve economies and successful implementation.

3. Status of Implementation of Smart Meters

IHDSL has installed a total of 14,586 as of November 30, 2011 which represents 99.08% of the total meters for the Residential, and GSLT50 customer classes. IHDSL installed 9958 smart meters in 2009, 4257 smart meters in 2010 and 371 smart meters in 2011.

Summary of Smart Meter Installations by Year

Installations	Meters Installed in 2009	Meters Installed in 2010	Meters Installed in 2011	Meters Installed in 2012	TOTAL
Residential Smart Meters Installed	9,958	3,707	131	23	13,819
General Service <50kW	0	550	240	112	902
Total Smart Meters Installed	9,958	4,257	371	135	**14,721**
Total CUMULATIVE Smart Meters Installed	9,958	14,215	14,586	**14,721**	

The remaining 135 meters (including forecasted growth) will be installed in 2012 for a total of 14,721 installed smart meters. This application seeks the recovery of the revenue requirements in respect of these smart meters as follows,

Summary of Smart Meter Capital and OM&A Costs Including MDM/R and TOU Beyond Minimum Functionality

Costs	Actual Costs for Meters Installed by 2010	Costs for Meters Installed in 2011	Projected Costs for Meters Installed in 2012	TOTAL Smart Meter Costs	TOTAL Cost per Smart Meter
Total of Smart Meter Capital Costs	$ 2,078,864	$ 115,950	$ -	**$ 2,194,814**	**$ 149.09**
Total of Smart Meter OM&A Costs	$ 283,733	$ 122,981	$ 165,200	**$ 571,914**	**$ 38.85**
Total of Smart Meter Costs	$ 2,362,597	$ 238,931	$ -	**$ 2,766,728**	**$ 187.94**

The above costs, with the exception of the capital and OM&A projected for the remainder of 2011 and 2012, are actual costs incurred in the deferral accounts 1555 and 1556 taken from IHDSL's audited financial records as of December 31, 2010.

4. Recovery of Smart Meter Funding:

IHDSL has been collecting funds associated with smart meter implementation since May 1, 2006. The basis for the recovery is outlined below:

- In the **2006** Decision and Order (EB-2005-0382) in accordance to the Generic Decision which provided $0.30 per month, per residential customer, to be added to IHDSL's revenue requirement. A monthly fixed charge of $0.28 metered customer per month effective May 1, 2006, was billed and the proceeds were credited in OEB Account 1555, Smart Meter Capital and Recovery Offset Variance Account.

- In the **2007** Decision and Order (EB-2007-0545), IHDSL received approval to continue the $0.28 per metered customer per month smart metering funding charge for the 2007 IRM rate year.

- In the **2008** Decision and Order (EB-2007-0845), IHDSL received approval to continue the $0.28 per metered customer per month smart metering funding charge for the 2008 IRM rate year.

- In the **2009** Decision and Order (EB-2008-0233), IHDSL received approval to continue the smart meter funding adder of $1.00 per metered customer per month previously approved by the Board.

- In its **2010** IRM Decision and Order (EB-2009-0232), IHDSL received approval for the smart meter funding adder of $2.00 per metered customer per month.

- In its **2011** IRM Decision and Order (EB-2010-0093), IHDSL received approval from the Board for a smart meter funding adder of $2.00.

5. **Project Overview**:

Addendum 2 is a project summary prepared by Util-Assist which outlines the various stages of the project and the due diligence undertaken at each step. The report, prepared on behalf of CHEC, outlines the details of each process, the RFPs undertaken, evaluations and the award of contracts.

CHEC LDCs recognized the benefits of collaboration early in the process through participation in the Ontario Utilities Smart Meter (OUSM) working group. Involvement in the OUSM group continued along with the engagement of Util-Assist for specific project management. The details of the implementation project and the prudence reviews are outlined in Addendum 2 and include:

- Participation in Ministry of Energy and Infrastructure authorized London Hydro AMI RFP process (establishing best practice procurement procedures)
- ODS RFP and award of contracts
- WAN RFP and award of contracts
- Meter Disposal RFQ
- Installation Service Provider RFP and award of contracts.

The RFPs are included in the addendums however the evaluations for each RFP are included in the confidential materials which have been provided.

6. Project Specifics:

6.1. AMI Selection:

Based on the London Hydro AMI RFP process IHDSL was awarded **Sensus' FlexNet™ AMI** system as the preferred vendor by the Fairness Commissioner (refer to the Attestation Letter of the Fairness Commissioner attached as Addendum 3).

6.2. Meter Deployment:

Based on the RFP process and evaluation it was determined that Trilliant most closely met the requirements for the mass deployment of meters. Addendum 3 contains the RFP for the award of contract.

Shortly after Triliant was selected as the winning proponent, Olameter acquired Trilliant resulting in Olameter providing the deployment services. The impact of this ownership change was evaluated and based on the existing relationship between Olameter and the LDCs and their performance in the industry, awarding the contract was deemed appropriate.

The deployment of meters started on September, 2009 and was scheduled to be completed by March, 2010. By the schedule date a total 14,215 smart meters were installed. Installation of the smart meters finished ahead of schedule primarily due to good weather conditions.

Summary of Smart Meter Installations by Year

Installations	Meters Installed in 2009	Meters Installed in 2010	Meters Installed in 2011	Meters Installed in 2012	TOTAL
Residential Smart Meters Installed	9,958	3,707	131	23	13,819
General Service <50kW	0	550	240	112	902
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Total CUMULATIVE Smart Meters Installed	9,958	14,215	14,586	**14,721**	

6.3. Meter Disposal:

Early 2009, IHDSL participated with CHEC, for the Meter Disposal RFI (included in Appendix 7 with confidential material). By March 2009, Greenport Recycling (Greenport) was the successful vendor selected from the RFI process. Greenport provided 2 storage bins to IHDSL's smart meter storage facility to hold all the conventional meters that were changed out and replaced with a smart meter. At the completion of the mass smart meter deployment process, Greenport removed the storage bins and recycled the conventional meters at a no cost option.

6.4. Operational Data Store (ODS) Functionality:

With the implementation of the AMI system a need was recognized for an application that supported full integration with the MDM/R and enabled staff to audit, validate, interact with and gain valuable business information from the wealth of meter data that was being collected. The AMI system, while fully capable of collecting meter read data and forwarding that raw data to the MDM/R, does not provide all of the functionality necessary to interpret and/or leverage the information it is providing in an educated and meaningful fashion.

An RFP was issued for an operational data store (ODS) in November 2008. Following the RFP process, shortlisted vendors delivered software demonstrations, leading to the selection of Kinetiq as the preferred vendor with their ODS application. Addendum 5 contains the RFP for the award of contract.

The primary requirements and features of the operational data store (ODS) are:

a) **Dashboard of Field Issues Possibly Requiring Intervention -** Dashboard visibility to the real-time performance of the smart meter system to assist staff in troubleshooting such issues as non-communicating meters, non-communicating tower gateways/collectors, etc.

b) **AMI SLA Audit -** Audit and reporting / real-time notification capabilities to monitor AMI performance and therefore ensure that data collection and submission service-level agreements (SLAs) with the centralized MDM/R are consistently met.

c) **Read Re-submission -** The ODS provides a data repository to facilitate backfilling reads after a meter installation, front-filling reads after a meter removal, and repla**cing reads labeled as NVE (Needs Verification or Edit) by the IESO MDM/R system**. The ODS provides a mechanism for meter data editing and VEE (Validation, Estimation and Editing) processes (in keeping with the MDM/R specifications), such data can then be re-submitted to the MDM/R. Features such as "register read validation failure resolution" is invaluable.

d) **IESO MDM/R Report Integration / Issue Resolution Automation -** The MDM/R produces a large volume of reports on a daily basis each potentially containing large amounts of information. Kinetiq downloads the MDM/R reports, and filter the information they provide in order to provide manageable, meaningful action items that can be prioritized, investigated and resolved.

e) **Meter Event Monitoring -** Dashboard visibility to report meter events and indicators such as outages, restorations, tampers, voltage changes, etc., many of which will afford the opportunity to improve the safety and reliability of the distribution system.

f) **Revenue Protection** – LDCs will be able to identify and respond to meter tampers which historically would have resulted in unidentified theft of power

g) **Outage Reporting -** Real-time outage information to facilitate faster response time, and therefore improved system reliability

7. Business Process Redesign

Throughout the latter half of 2009 and early 2010, the Util-Assist training team delivered a series of education sessions covering the MDM/R design specifications, meter read data, VEE and other billing processes, and the design of a testing/cutover strategy. LDCs have widely recognized that a number of business processes, including new account setup, meter installations, meter changes, move-in/move-out and final billing all require scrutiny and procedural modifications to ensure that MDM/R integrations are optimized. Actual business process redesign is an ongoing process leading up to and after cutover.

8. System Changes

IHDSL uses the HARRIS Northstar billing system, which is widely used by other Ontario LDCs. Modifications or additional modules to the existing billing systems were undertaken as part of the smart meter deployment and implementation of time of use billing. It was fully expected that existing systems could be modified to accommodate as illustrated by the successful implementation of time of use billing in other LDCs. The required add-ons software modules and professional services for the existing system, to ensure the integration was completed in the defined regulatory timelines, were negotiated and implemented.

9. Integration with MDM/R

To assist with the integration to the provincial Meter Data Management Repository (MDM/R) staff attended relevant IESO training sessions as well as further training sessions provided by Util-Assist.

Registration paperwork and integration project plan were filed with the IESO in October and December, 2009 respectively.

AS2 connectivity software to facilitate data integration with the MDM/R was selected and installed in March, 2010 and connectivity testing was successfully completed with the IESO on March 31, 2010.

The project plan called for Unit Testing to be executed in the April to June, 2010 timeframe but due to some delays, the integration project plan was re-filed and a new wave assignment was approved. Under the revised plan, unit testing was completed as scheduled in December, 2010 and System Integration (SIT) and Qualification Testing (QT) were completed in January and March, 2011 respectively in preparation for cutover to live data transfer with the MDMR by March 8, 2011.

The ability to meet these targeted timelines was to a large extent contingent upon various software systems delivering the promised functionality and suppliers meeting their contractual obligations. Cutover to production was attained on March 28, 2011.

10.Transition to Time of Use Pricing

In mid-2009, the Ontario Government articulated an expectation that 1 million RPP customers would be billed using TOU pricing by the summer of 2010, rising to 3.6 million customers by June 2011. On June 24, 2010, the Ontario Energy Board issued a proposed determination regarding mandated time-of-use pricing for regulated price plan customers (Board File No. EB-2010-0218), suggesting that distributor-specific TOU dates would be the most appropriate approach, as it allows for the deadline to logically follow MDM/R enrolment activities.

In a letter dated August 4, 2010, the OEB provided direction to all LDCs on mandated dates in which each distributor musty bill RPP customers that have eligible TOU meters using TOU pricing.

IHDSL's mandated date for TOU billing was June 1, 2011 for all residential and general service <50kW customers. IHDSL confirms that eligible customers were billed TOU pricing on June consumption, billed in July, 2011.

11.Customer Education

IHDSL executed an extensive ongoing customer education and outreach campaign to educate and inform customers of IHDSL's smart meter project status and TOU rollout schedule and impact. Beginning in April 2009, bill inserts were mailed out to all IHDSL's Residential and General Service less than 50 kW customers as notification of their pending smart meter installation. This notified the customers that their conventional meter would be removed and replaced with a smart meter within the next few months. The insert also informed the customer how the smart meter would be installed, instructed the customer that they would not have to show their hydro bill nor sign a contract, as well as letting them know that there would be no changes to their rates or how they would be billed at this time.

Throughout the smart meter installation timeframe, on the day of the customer's actual smart meter installation, the customer received a plastic door hanger smart meter welcome package which included a letter from IHDSL notifying them that their meter was changed out that day and the Ministry of Energy booklet 'Getting Smart About Smart Meters Answer Book'.

Throughout 2010-2011 all conservation outreach activities undertaken by IHDSL focused on energy usage awareness, energy conservation tips and energy programs/rebates to assist customers with the transition to TOU pricing.

In early 2011, bill inserts were again mailed out to all of IHDSL's customers to inform them of upcoming community information sessions being held in IHDSL's service territory. 11 customer information sessions were held throughout April-June and provided IHDSL and their customers with a face to face forum allowing IHDSL to inform customers of: upcoming TOU changes and explain the potential impact this would have on their bill in July 2011, energy conservation tips, safety tips and open floor discussion to address any customer questions or concerns.

In late April 2011, a welcome letter with TOU pricing, decals and a "Quick Guide to TOU Rates" were mailed out to all Residential and General Service less than 50kW customers.

In August 2011, bill inserts entitled "Managing Your Electricity Costs" were included in all IHDSL's customers' bills to further assist customers in taking advantage of TOU rates to lower electricity costs.

Looking ahead to 2012, IHDSL has slated follow up bill inserts in an effort to further educate customers on the following topics:

- Reminder tips on how to maximize TOU pricing peaks
- Available monitoring tools for usage (web presentment)
- Register reads on the invoice

12. Web Presentment

The Ministry of Energy and Infrastructure has indicated that electricity customers should ideally have web access to their hourly consumption data allowing them the opportunity to make informed decisions and ultimately affect their TOU pricing load.

In 2011, IHDSL participated in a group RFP which resulted in the purchase and implementation of the Harris Computer Systems Customer Connect software. This software provides a web presentment tool fully integrated with IHDSL's Harris Northstar eCare and billing system. This software enables the customer to view, through their existing online eCare portal, their actual hourly usage data in the MDM/R the following morning.

13. Annual Security Audit:

With the mass deployment of AMI systems, security of the AMI network is critical to prevent utilities from becoming susceptible to new levels of potential security breaches and to ensure customer privacy and acceptance of the network. By installing network infrastructure in the field, there is now a requirement for additional security measures in order to ensure that utility data and equipment are kept secure from manipulation or other forms of control. As networks are deployed throughout the world, cyber security articles with reports of the potential for smart-grid hacking are becoming commonplace in the media.

The minimum Functional Specification for an Advanced Metering Infrastructure (AMI) released in July 2006 identified the need for security within the AMI network – Section 2.11 Security and Authentication: "The AMI shall have security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements." Some of the privacy and network security infrastructure concerns that have been raised include:

- Monitoring a consumer's usage;
- Modifying one's own, or another consumer's usage;
- Interrupting the power of one or more consumers; and
- Tampering with demand side management tools which can be controlled through smart meters.

Since early 2009, Ontario utilities have been working with their smart meter providers to understand the security features of the networks, best practices for their deployment and new features that are being developed for future implementation within the smart meter networks. In November 2009 the Information and Privacy Commissioner of Ontario released the report Smart Privacy for the Smart Grid which identified areas of concern to be addressed in the area of smart meter and smart grid devices.
Going forward, annual security audit has been budgeted, as this is a prudent approach to satisfying the due diligence requirements for protection not only of the customer information, but also to ensure that access to the infrastructure is properly protected, thereby securing against unwanted modifications to data collection and/or load-control functionality. Security of the network and ensuring that customer data is protected at all times has resulted in the development of governance standards requiring extensive security measures such as NERC (North American Electric Reliability Corporation). The NERC reliability standards are developed by the electricity industry using a balanced, open, fair and inclusive process managed by the NERC Standards Committee.

For many Ontario LDCs, including IHDSL, completing a security audit at a NERC, NIST (Network Information Security & Technology) or comparable level would be a cost-prohibitive exercise. Therefore, a consortium of 31 Ontario LDCs has worked together with a consultant in the issuance of the November 2010 "Smart Meter Network Security Audit Services" Request for Proposal.

The objective of the RFP was to select an audit partner who would complete a security audit of the Sensus AMI systems for consortium members with Sensus technology in place, and to the work with Sensus towards the implementation of viable countermeasures to resolve all security concerns. The selected audit firm first completed an in-depth security review at one participating LDC in the consortium that has the Sensus solution. Once this review is complete, the audit firm then reviewed completed infrastructure questionnaire from all remaining participating LDC's to confirm that their Sensus AMI systems are configured in the same manner as the lead LDC. The security audits have included end to end AMI infrastructure from the meter to utility systems and home area network. The final security audit report will be available in late January, 2012.

14. Copies of Agreements

The following agreements are being filed with the Board Secretary on a confidential basis:

Advanced Metering Infrastructure Services Agreement between IHDSL and Sensus Inc.;

Smart Meter Installation Agreement between IHDSL and Olameter Inc; and

Operational Data Store Agreement between IHDSL and Kinetiq Inc.;

RFP evaluations which include the pricing from each vendor.

Sensus Inc., Olameter Inc. and Kinetiq Inc. are corporations which are engaged in competitive businesses. The disclosure of the terms of these agreements could reasonably be expected to prejudice the economic interests, competitive positions and cause undue financial interests of Sensus Inc., Kinetiq and Olameter respectively, since it would enable their competitors to ascertain the scope and pricing of services provided by these companies. The Board's Practice Direction on Confidential Filings (the "Practice Direction") recognizes that these are among the factors that the Board will take into consideration when addressing the confidentiality of filings. They are also addressed in section 17(1) of the Freedom of Information and Protection of Privacy Act ("FIPPA"), and the Practice Direction notes (at Appendix C of the Practice Direction) that third party information as described in subsection 17(1) of FIPPA is among the types of information previously assessed or maintained by the Board as confidential. Accordingly, IHDSL requests that these Agreements be kept confidential.

IHDSL is prepared to provide copies of the Agreements to parties' counsel and experts or consultants provided that they have executed the Board's form of Declaration and Undertaking with respect to confidentiality and that they comply with the Practice Direction, subject to IHDSL's right to object to the Board's acceptance of a Declaration and Undertaking from any person.

In keeping with the requirements of the Practice Direction, IHDSL is filing confidential unredacted versions of the Agreements under separate cover, in a sealed envelope marked "Confidential".

15. Justification for Functionality that Exceeds Minimum Functionality:

The installed meters and systems do not exceed the minimum functionality as specified in O. Reg. 425/06 with the exception of IHDSL's MDM/R and TOU costs, identified within the OEB provided model sections 1.6 and 2.6 respectively. IHDSL has not included any IESO MDM/R operating fees in this filing, IHDSL does not have a billing MDM/R system and IHDSL uses only the Smart Meter Entity MDM/R system for billing TOU customers.

16. Cost Variance:

IHDSL is seeking recovery of costs relating to the 14,721 smart meters placed into the distribution territory by December 31, 2012. The following table provides a comparison of the actual and projected smart meter costs to the forecasted 2010 IRM smart meter filing.

Comparison of 2010 Actual and 2011/2012 Projected Smart Meter Costs to Estimated Smart Meter Costs					
	Costs for Meters Installed by 2010	Projected Costs for Meters Installed in 2011/2012	TOTAL	Forecast per 2010 IRM Application	Variance
Number of Smart Meters Installations	**14,215**	**506**	**14,721**	**14,730**	**- 9**
1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	$ 1,555,941	$ 69,407	$ 1,625,348	$ 2,298,681	$ 673,333
1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)	$ 274,310	$ -	$ 274,310	$ 614,670	$ 340,360
1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	$ -	$ -	$ -	$ 258,126	$ 258,126
1.4 WIDE AREA NETWORK (WAN)	$ -	$ -	$ -	$ -	$ -
1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY	$ 248,613	$ 2,999	$ 251,612	$ 239,966	-$ 11,646
Total Capital Costs Related to Minimum Functionality	**$ 2,078,864**	**$ 72,406**	**$ 2,151,270**	**$ 3,411,443**	**$ 1,260,173**
1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY (MDM/R & TOU)	$ -	$ 43,544	$ 43,544	$ -	-$ 43,544
Total Smart Meter Capital Costs	**$ 2,078,864**	**$ 115,950**	**$ 2,194,814**	**$ 3,411,443**	**$ 1,216,629**
Capital Costs Related to Minimum Functionality per Smart Meter	$ 146.24	$ 143.09	$ 146.14	$ 231.60	
Capital Costs Beyond Minimum Functionality (MDM/R & TOU) per Smart Meter	$ -	$ 86.06	$ 2.96	$ -	
TOTAL Capital Costs per Smart Meter	**$ 146.24**	**$ 229.15**	**$ 149.09**	**$ 231.60**	
2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	$ 5,516	$ -	$ 5,516	$ 274,791	$ 269,275
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)	$ -	$ -	$ -	$ 41,853	$ 41,853
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	$ 101,274	$ 40,559	$ 141,833	$ 131,860	-$ 9,973
2.4 WIDE AREA NETWORK (WAN)	$ 1,000	$ 1,278	$ 2,278	$ -	-$ 2,278
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY	$ 35,574	$ 98,532	$ 134,106	$ 220,002	$ 85,896
Total OM&A Costs Related to Minimum Functionality	**$ 143,364**	**$ 140,369**	**$ 283,733**	**$ 668,506**	**$ 384,773**
2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY	$ -	$ 179,992	$ 179,992	$ -	-$ 179,992
Total Smart Meter OM&A Costs	**$ 143,364**	**$ 320,361**	**$ 463,725**	**$ 668,506**	**$ 204,781**
OM&A Costs Related to Minimum Functionality per Smart Meter	$ 10.09	$ 277.41	$ 19.27	$ 45.38	
OM&A Costs Beyond Minimum Functionality (MDM/R & TOU) per Smart Meter	$ -	$ 355.72	$ 12.23	$ -	
TOTAL OM&A Costs per Smart Meter	**$ 10.09**	**$ 633.12**	**$ 31.50**	**$ 45.38**	

Capital costs and OM&A costs related to minimum functionality are lower than forecasted 2010 IRM smart meter submission due to the favorable U.S. dollar exchange conversion, a forecasted standalone Regional Network Interface (RNI) verses a shared RNI and faster installations due to favorable weather conditions.

IHDSL has included capital costs beyond minimum functionality (MDM/R & TOU) in section 1.6. These capital costs are the required CIS system upgrade and related support for the MDM/R integration and TOU implementation.

IHDSL has included the OM&A costs beyond minimum functionality (MDM/R & TOU) in section 2.6. These OM&A costs include customer education, MDM/R integration and operation consulting, CIS system maintenance costs and web presentment maintenance costs. In determination of the costs beyond minimum functionality, IHDSL only included calculations that were beyond costs identified in our 2009 COS application EB-2008-0233.

16.1. Stranded Meter Costs

IHDSL is not seeking disposition of its stranded meter costs. IHDSL continues to recover these costs by including the net book value of stranded meters in its rate base for rate-making purposes, as recommended by the Board in its Decision with Reasons in the Combined Proceeding.

As of December 31, 2010, Lakefront Utilities Inc. had replaced 8,819 conventional meters with smart meters. The net book value of the stranded conventional meters at December 31, 2010 was $382,294. IHDSL continues to amortize the stranded meters over the remaining amortization period.

Proceeds on the scrapped meters are captured in account 1555 as an offset to the costs in the deferral account, in accordance with the Board's Guideline 2008-0002 and the Board's January 16, 2007 letter to distributors on stranded meter costs related to the installation of smart meters, reproduced as Appendix B to the Guideline.

17. Smart Meter Disposition Rate Rider Calculations:

In preparing the Smart Meter Prudence Review Application, IHDSL utilized Version 2.17 of the Boards Smart Meter model. A copy of the Smart Meter Model accompanies this application as Appendix 1. The following table summarizes the total capital and OM&A costs for IHDSL's smart meter project.

Summary of Smart Meter Capital and OM&A Costs Including MDM/R and TOU Beyond Minimum Functionality

Costs	Actual Costs for Meters Installed by 2010	Costs for Meters Installed in 2011	Costs for Meters Installed in 2012	TOTAL Smart Meter Costs	TOTAL Cost per Smart Meter
Total of Smart Meter Capital Costs	$ 2,078,864	$ 115,950	$ -	**$ 2,194,814**	**$ 149.09**
Total of Smart Meter OM&A Costs	$ 143,364	$ 241,561	$ 78,800	**$ 463,725**	**$ 31.50**
Total of Smart Meter Costs	$ 2,222,228	$ 357,511	$ -	**$ 2,658,539**	**$ 180.60**

The following table identifies the revenue requirement of $1,1153,080.00 associated with the smart meter costs.

Revenue Requirement Calculation for Disposition Rate Rider

Rate Base	2007	2008	2009	2010	2011	Total
Net Fixed Assets	$ 7,879	$ 22,932	$ 720,197	$ 1,511,260	$ 1,609,206	$ 3,871,474
Working Capital Allowance	$ -	$ -	$ 5,989	$ 15,516	$ 36,234	$ 57,739
Total Rate Base	**$ 7,879**	**$ 22,932**	**$ 726,186**	**$1,526,776**	**$1,645,440**	**$3,929,213**

Revenue Requirement	2007	2008	2009	2010	2011	Total
Short Term Interest	$ -	$ 84	$ 465	$ 962	$ 1,012	$ 2,523
Long Term Interest	$ 246	$ 1,039	$ 33,507	$ 73,748	$ 77,589	$ 186,129
Return on Equity	$ 355	$ 964	$ 30,291	$ 57,959	$ 60,978	$ 150,547
Total Return	$ 601	$ 2,087	$ 64,263	$ 132,669	$ 139,579	$ 339,199
OM&A	$ -	$ -	$ 39,924	$ 103,440	$ 241,561	$ 384,925
Amortization	$ 543	$ 1,619	$ 62,093	$ 132,365	$ 146,560	$ 343,180
Grossed-up PILs	$ 174	$ 416	$ 18,391	$ 28,398	$ 28,102	$ 75,482
Revenue Requirement	$ 1,318	$ 4,122	$ 184,671	$ 396,872	$ 555,802	**$1,142,786**
Interest on Deferred OM&A and Amortizatio	$ 13	$ 54	$ 605	$ 1,771	$ 7,851	$ 10,294
Total Revenue Requirement	**$ 1,331**	**$ 4,176**	**$ 185,276**	**$ 398,643**	**$ 563,653**	**$1,153,080**

The next table summarizes the Smart meter true-up balance for the disposition rider.

Total Revenue Requirement	$	1,153,080
Smart Meter Funding Adder Collected	-$	1,035,636
Smart Meter True-up Balance for Disposition Rider	**$**	**117,444**

Once the balance of the rider was determined an exercise was undertaken to determine the allocation of the rider to the customer classes covered by the rider (Residential and General Service less than 50kW).

The basis for the allocation is as follows,

- Return (deemed interest plus return on equity) and Amortization have been allocated based on the Weighted Average of the Residential and General Service less than 50kW 1860 Weighted Meter Capital (CWMC) allocators in the 2006 Cost Allocation Review;
- OM&A has been allocated based on the number of meters installed for each class;
- PILs have been allocated based on the revenue requirement allocated to each class before PILs; and
- Smart Meter Funding Adder collected, including carrying costs, has been allocated based on the revenue requirement allocated to each class before PILS.

Basis of Allocation for by Customer Class for SMDR &SMIRR Rate Riders

Revenue Requirement **Return & Amortization:**	**1860 CWMC Allocator per 2006 Cost Allocation Review**	**Revenue Requirement Smart Meter Allocator**	
Residential (1)	67.90%	**75.78%**	(1) / (A)
GS<50 (2)	21.70%	**24.22%**	(2) / (A)
Subtotal Applicable to Smart Meters (A)	**89.60%**	100.00%	
GS>50	10.40%		
Total	100.00%		
Revenue Requirement **OM&A**	**Meters Installed by 2011**	**Revenue Requirement Smart Meter Allocator**	
Residential (3)	13,819	**93.87%**	(3) / (B)
GS<50 (4)	902	**6.13%**	(4) / (B)
Total Smart Meters Installed (B)	**14,721**		
Revenue Requirement **Grossed-up PILS & Interest on Deferred OM&A and Amortization**	**Revenue Requirement Allocated for Return, Amortization and OM&A**	**Revenue Requirement Smart Meter Allocator**	
Residential (5)	$ 878,455	**82.31%**	(5) / (C)
GS<50 (6)	$ 188,849	**17.69%**	(6) / (C)
Total Smart Meters Installed (C)	**$ 1,067,304**		

Allocation of Revenue Requirement and Smart Meter Funding Adder by Customer Class for Disposition Rate Rider

Revenue Requirement	**Total to Allocate**	**Allocator for Residential**	**Residential**	**Allocator for GS<50**	**GS<50**	
Return	$ 339,199	75.78%	$ 257,049	24.22%	$ 82,150	
Amortization	$ 343,180	75.78%	$ 260,066	24.22%	$ 83,114	
OM&A	$ 384,925	93.87%	$ 361,339	6.13%	$ 23,586	
Subtotal before PILs	$ 1,067,304		$ 878,455	(5)	$ 188,849	(6)
Grossed-up PILs	$ 75,482	82.31%	$ 62,126	17.69%	$ 13,356	
Interest on Deferred OM&A and Amortization	$ 10,294	82.31%	$ 8,473	17.69%	$ 1,821	
Total Revenue Requirement	$ 1,153,080	82.31%	$ 949,054	17.69%	$ 204,026	
Total Smart Meter Funding Adder Collected	-$ 1,035,636	82.31%	-$ 852,390	17.69%	-$ 183,246	
Total Smart Meter True-up Balance	**$ 117,444**	82.31%	**$ 96,663**	17.69%	**$ 20,781**	

The outcome of the allocation exercise determined an allocator of 82.31% for the Residential rate class and 17.69% for the General Service less than 50kW rate class. Utilizing the Smart Meter True Up balance of $117,444.00 the SMDR rider has been calculated as follows,

Calculation of Disposition Rate Rider by Class (SMDR)

	Residential	GS<50	Total Smart Meter Customers
Total Smart Meter True-up for Disposition	$ 96,663	$ 20,780	$ 117,443
Number of Customers	13,819	902	14,721
Total Monthly Disposition Rate Rider	**$ 0.29**	**$ 0.96**	**$ 0.33**

IHDSL has specifically requested a 2 year disposition of the Disposition Rate Rider (SMDR) in conjunction with the Group 1 DVA accounts in IHDSL's IRM 2012 submission EB-2011-0176. It is IHDSL's belief that the 2 year disposition will assist in flattening potential rate spikes with the introduction of the SMIRR and IHDSL's upcoming COS service application .

In determining the Smart Meter Incremental Revenue Requirement (SMIRR) rate rider, IHDSL utilized the same allocation % for the Residential and General Service less than 50kW rate classes.

Calculation of Incremental Revenue Requirement Rate Rider by Class (SMIRR)

	Residential	GS<50	Total Smart Meter Customers
Total Smart Meter True-up for Disposition	$ 314,053	$ 67,515	$ 381,568
Number of Customers	13,819	902	14,721
Total Monthly Disposition Rate Rider	**$ 0.95**	**$ 3.12**	**$ 2.16**

18. Bill Impacts

In order to determine the bill impacts for the rate groups impacted by changes to the SMDR and the introduction of the SMIRR, IHDSL first of all looked at the "stand alone" changes on bill specific to Smart Metering.

The allocation exercise shows an overall decrease in smart metering rate riders for the Residential customers of $0.76 per metered customer. However the General Service less than 50kW customers have an overall increase of $2.08 per metered customer.

Summary of Smart Meter Rate Changes (Stand Alone)

Rate Rider - Residential	Before	After	Inc/(Dec)
Smart Meter Funding Adder	$ 2.00	$ -	-$ 2.00
Smart Meter Disposition (SMDA)	$ -	$ 0.29	$ 0.29
Smart Meter Incremental Revenue Requirement	$ -	$ 0.95	$ 0.95
Total Smart Meter Rate Change - Resident	**$ 2.00**	**$ 1.24**	**-$ 0.76**

Rate Rider - GS<50 kW	Before	After	Inc/(Dec)
Smart Meter Funding Adder	$ 2.00	$ -	-$ 2.00
Smart Meter Disposition (SMDA)	$ -	$ 0.96	$ 0.96
Smart Meter Incremental Revenue Requirement	$ -	$ 3.12	$ 3.12
Total Smart Meter Rate Change - GS<50 k|	**$ 2.00**	**$ 4.08**	**$ 2.08**

In order to fully understand the bill impact for IHDSL's customers effective May 1, 2012, the "true" rider amounts of $1.24 for the Residential customers and $4.08 for the General Service less than 50kW customers were layered to IHDSL's IRM EB-2011-0176 bill impact analysis which did not reflect the current $2.00 SMFA. IHDSL is of the position that the positive impact on the Residential and General Service less than 50kW customer classes supports the requested 2 year disposition of the SMDR rider.

Summary of Bill Impacts -Smart Meter Rate Changes In Conjuction with 2012 IRM EB-2011-0176

Customer Class	Current Mthly Total	IRM Mthly	Inc/(Dec)	% Inc/(Dec	IRM & SM	IRM & SM	IRM & SM %
Residential - 800 kW	$ 121.04	$ 114.34	-$ 6.70	-6%	$ 115.58	-$ 5.46	-5%
GS< 50kW - 2000 kW	$ 272.75	$ 255.00	-$ 17.75	-7%	$ 259.08	-$ 13.67	-5%

19. Conclusion

IHDSL is seeking approval of the smart meter costs identified within this application and the transfer of the approved amounts from the smart meter deferral accounts to the appropriate fixed asset, revenue and expense accounts.

IHDSL respectfully submits that the costs identified within this application were necessary to fulfill its obligations under the provincially mandated Smart Meter Initiative and that they have been prudently incurred in accordance with Board guidelines; the proposed rate riders are just and reasonable; the associated bill impacts are minimal; and it is therefore appropriate that the Board approve the proposed rate riders for implementation effective May 1, 2012.

20. Addendums:

20.1. Addendum 1 **OEB Smart Meter Rate Model**

20.2. Addendum 2 **Util-Assist – CHEC Smart Meter Summary Report**

20.3. Addendum 3 **Attestation Letter of the Fairness Commissioner**

20.4. Addendum 4 **Meter Deployment RFP**

20.5. Addendum 5 **Operational Data Store RFP**

20.6. Addendum 6 **Confidential Materials Filed with Board**

- Review of Management Contract – January 2010
- Meter Deployment RFP Evaluation
- Operational Data Store RFP Evaluation
- WAN RFP Evaluation
- Copies of contract with vendors.

V 2.17

Ontario Energy Board

Smart Meter Model

Choose Your Utility:

Hydro Ottawa Limited
Innisfil Hydro Distribution Systems Limited

Application Contact Information

Name:	Brenda Pinke
Title:	Regulatory Manager
Phone Number:	705-431-6870 ext 262
Email Address:	brendap@innisfilhydro.com
We are applying for rates effective:	May 1, 2012
Last COS Re-based Year	2009

Legend

DROP-DOWN MENU

INPUT FIELD

CALCULATION FIELD

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While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results. The use of any models and spreadsheets does not automatically imply Board approval. The onus is on the distributor to prepare, document and support its application. Board-issued Excel models and spreadsheets are offered to assist parties in providing the necessary information so as to facilitate an expeditious review of an application. The onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Smart Meter Model

Innisfil Hydro Distribution Systems Limited

Distributors must enter all incremental costs related to their smart meter program and all revenues recovered to date in the applicable tabs except for those costs (and associated revenues) for which the Board has approved on a final basis, i.e. capital costs have been included in rate base and OM&A costs in revenue requirement.

For 2012, distributors that have completed their deployments by the end of 2011 are not expected to enter any capital costs. However, for OM&A, regardless of whether a distributor has deployments in 2012, distributors should enter the forecasted OM&A for 2012 for all smart meters in service.

		2006	2007	2008	2009	2010	2011	2012 and later	Total
Smart Meter Capital Cost and Operational Expense Data		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
Smart Meter Installation Plan									
Actual/Planned number of Smart Meters installed during the Calendar Year									
Residential					9,958	3,707	131	23	13819
General Service < 50 kW						550	240	112	902
Actual/Planned number of Smart Meters installed (Residential and GS < 50 kW only)		0	0	0	9958	4257	371	135	14721
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed		0.00%	0.00%	0.00%	67.64%	96.56%	99.08%	100.00%	100.00%
Actual/Planned number of GS > 50 kW meters installed									0
Other (please identify)									0
Total Number of Smart Meters installed or planned to be installed		0	0	0	9958	4257	371	135	14721

1 Capital Costs

	Asset Type Asset type must be selected to enable calculations	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)									
1.1.1 Smart Meters *(may include new meters and modules, etc.)*	Smart Meter				1,157,287	187,674	54,005		$ 1,398,966
1.1.2 Installation Costs *(may include socket kits, labour, vehicle, benefits, etc.)*	Smart Meter				138,026	72,954	15,402		$ 226,382
1.1.3a Workforce Automation Hardware *(may include fieldwork handhelds, barcode hardware, etc.)*									$ -

	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.1.3b Workforce Automation Software *(may include fieldwork handhelds, barcode hardware, etc.)*									$ -
Total Advanced Metering Communications Devices (AMCD)		$ -	$ -	$ -	$ 1,295,313	$ 260,628	$ 69,407	$ -	$ 1,625,348
1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)									
1.2.1 Collectors	Other Equipment				274,110	200			$ 274,310
1.2.2 Repeaters *(may include radio licence, etc.)*									$ -
1.2.3 Installation *(may include meter seals and rings, collector computer hardware, etc.)*									$ -
Total Advanced Metering Regional Collector (AMRC) (Includes LAN)		$ -	$ -	$ -	$ 274,110	$ 200	$ -	$ -	$ 274,310

1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.3.1 Computer Hardware									$ -
1.3.2 Computer Software									$ -
1.3.3 Computer Software Licences & Installation (includes hardware and software) *(may include AS/400 disk space, backup and recovery computer, UPS, etc.)*									$ -
Total Advanced Metering Control Computer (AMCC)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1.4 WIDE AREA NETWORK (WAN)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.4.1 Activiation Fees									$ -
Total Wide Area Network (WAN)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.5.1 Customer Equipment *(including repair of damaged equipment)*									$ -
1.5.2 AMI Interface to CIS	Computer Software				32,533				$ 32,533
1.5.3 Professional Fees	Smart Meter		16,301	15,967	44,545	24,934	2,999		$ 104,746
1.5.4 Integration	Smart Meter				87,664	25,572			$ 113,236
1.5.5 Program Management									$ -
1.5.6 Other AMI Capital	Smart Meter				2,479	-1,382			$ 1,097
Total Other AMI Capital Costs Related to Minimum Functionality		$ -	$ 16,301	$ 15,967	$ 167,221	$ 49,124	$ 2,999	$ -	$ 251,612
Total Capital Costs Related to Minimum Functionality		$ -	$ 16,301	$ 15,967	$ 1,736,644	$ 309,952	$ 72,406	$ -	$ 2,151,270

1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06	Computer Software								$ -
1.6.2 Costs for deployment of smart meters to customers other than residential and small general service	Computer Software								$ -
1.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.	Smart Meter						43,544		$ 43,544

Total Capital Costs Beyond Minimum Functionality	$ -	$ -	$ -	$ -	$ -	$ 43,544	$ -	$ 43,544
Total Smart Meter Capital Costs	$ -	$ 16,301	$ 15,967	$ 1,736,644	$ 309,952	$ 115,950	$ -	$ 2,194,814

2 OM&A Expenses

		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)									
2.1.1 Maintenance *(may include meter reverification costs, etc.)*									$ -
2.1.2 Other *(please specifiy)*	Meter base repairs				1,673	3,843			$ 5,516
Total Incremental AMCD OM&A Costs		$ -	$ -	$ -	$ 1,673	$ 3,843	$ -	$ -	$ 5,516
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)									
2.2.1 Maintenance									$ -
2.2.2 Other *(please specifiy)*									$ -
Total Incremental AMRC OM&A Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)									
2.3.1 Hardware Maintenance *(may include server support, etc.)*									$ -
2.3.2 Software Maintenance *(may include maintenance support, etc.)*					29,387	71,887	40,559		$ 141,833
2.3.2 Other *(please specifiy)*									$ -
Total Incremental AMCC OM&A Costs		$ -	$ -	$ -	$ 29,387	$ 71,887	$ 40,559	$ -	$ 141,833
2.4 WIDE AREA NETWORK (WAN)									
2.4.1 WAN Maintenance						1,000	1,278		$ 2,278
2.4.2 Other *(please specifiy)*									$ -
Total Incremental AMRC OM&A Costs		$ -	$ -	$ -	$ -	$ 1,000	$ 1,278	$ -	$ 2,278
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY									
2.5.1 Business Process Redesign									$ -
2.5.2 Customer Communication (may include project communication, etc.)					8,864				$ 8,864
2.5.3 Program Management						5,835	78,861		$ 84,696
2.5.4 Change Management (may include training, etc.)						20,875	19,671		$ 40,546
2.5.5 Administration Costs									$ -
2.5.6 Other AMI Expenses *(please specify)*									$ -
Total Other AMI OM&A Costs Related to Minimum Functionality		$ -	$ -	$ -	$ 8,864	$ 26,710	$ 98,532	$ -	$ 134,106
TOTAL OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY		$ -	$ -	$ -	$ 39,924	$ 103,440	$ 140,369	$ -	$ 283,733
2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual		

(Please provide a descriptive title and identify nature of beyond minimum functionality costs)

2.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06								$ -
2.6.2 Costs for deployment of smart meters to customers other than residential and small general service								$ -
2.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.						101,192	78,800	$ 179,992
Total OM&A Costs Beyond Minimum Functionality	$ -	$ -	$ -	$ -	$ -	$ 101,192	$ 78,800	$ 179,992
Total Smart Meter OM&A Costs	$ -	$ -	$ -	$ 39,924	$ 103,440	$ 241,561	$ 78,800	$ 463,725

3 Aggregate Smart Meter Costs by Category

3.1	**Capital**								
3.1.1	Smart Meter	$ -	$ 16,301	$ 15,967	$ 1,430,001	$ 309,752	$ 115,950	$ -	$ 1,887,971
3.1.2	Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.3	Computer Software	$ -	$ -	$ -	$ 32,533	$ -	$ -	$ -	$ 32,533
3.1.4	Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.5	Other Equipment	$ -	$ -	$ -	$ 274,110	$ 200	$ -	$ -	$ 274,310
3.1.6	Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.7	**Total Capital Costs**	**$ -**	**$ 16,301**	**$ 15,967**	**$ 1,736,644**	**$ 309,952**	**$ 115,950**	**$ -**	**$ 2,194,814**
3.2	**OM&A Costs**								
3.2.1	**Total OM&A Costs**	**$ -**	**$ -**	**$ -**	**$ 39,924**	**$ 103,440**	**$ 241,561**	**$ 78,800**	**$ 463,725**

Innisfil Hydro Distribution Systems Limited

	2006	2007
Cost of Capital		
Capital Structure[1]		
Deemed Short-term Debt Capitalization		
Deemed Long-term Debt Capitalization	50.0%	50.0%
Deemed Equity Capitalization	50.0%	50.0%
Preferred Shares		
Total	100.0%	100.0%
Cost of Capital Parameters		
Deemed Short-term Debt Rate		
Long-term Debt Rate (actual/embedded/deemed)[2]	6.25%	6.25%
Target Return on Equity (ROE)	9.0%	9.00%
Return on Preferred Shares		
WACC	7.63%	7.63%
Working Capital Allowance		
Working Capital Allowance Rate	15.0%	15.0%
(% of the sum of Cost of Power + controllable expenses)		
Taxes/PILs		
Aggregate Corporate Income Tax Rate	36.12%	36.12%
Capital Tax (until July 1st, 2010)	0.30%	0.225%
Depreciation Rates		
(expressed as expected useful life in years)		
Smart Meters - years	15	15
- rate (%)	6.67%	6.67%
Computer Hardware - years	5	5
- rate (%)	20.00%	20.00%
Computer Software - years	3	3
- rate (%)	33.33%	33.33%

Tools & Equipment - years	10	10
- rate (%)	10.00%	10.00%
Other Equipment - years	20	20
- rate (%)	5.00%	5.00%

CCA Rates

Smart Meters - CCA Class	47	47
Smart Meters - CCA Rate	8%	8%
Computer Equipment - CCA Class	8	8
Computer Equipment - CCA Rate	20%	20%
General Equipment - CCA Class		
General Equipment - CCA Rate		
Applications Software - CCA Class		
Applications Software - CCA Rate		

Assumptions

[1] *Planned smart meter installations occur evenly throughout the year.*
[2] *Fiscal calendar year (January 1 to December 31) used.*
3 *Amortization is done on a striaght line basis and has the "half-year" rule applied.*

Ontario Energy Board

Smart Meter Model

2008	2009	2010	2011	2012 and later
4.0%	4.0%	4.0%	4.0%	4.0%
49.3%	52.7%	56.0%	56.0%	56.0%
46.7%	43.3%	40.0%	40.0%	40.0%
100.0%	100.0%	100.0%	100.0%	100.0%
9.19%	1.33%	1.33%	1.33%	1.33%
9.19%	7.28%	7.28%	7.28%	7.28%
9.00%	8.01%	8.01%	8.01%	8.01%
9.10%	7.36%	7.33%	7.33%	7.33%
15.0%	15.0%	15.0%	15.0%	15.0%
33.50%	33.00%	31.00%	28.25%	26.25%
0.225%	0.225%	0.075%	0.00%	0.00%
15	15	15	15	15
6.67%	6.67%	6.67%	6.67%	6.67%
5	5	5	5	5
20.00%	20.00%	20.00%	20.00%	20.00%
3	3	3	3	3
33.33%	33.33%	33.33%	33.33%	33.33%

10	10	10	10	10
10.00%	10.00%	10.00%	10.00%	10.00%
20	20	20	20	20
5.00%	5.00%	5.00%	5.00%	5.00%
47	47	47	47	47
8%	8%	8%	8%	8%
8	8	8	8	8
20%	20%	20%	20%	20%

Ontario Energy Board

Smart Meter Model

Innisfil Hydro Distribution Systems Limited

	2006	2007	2008	2009	2010	2011
Net Fixed Assets - Smart Meters						
Gross Book Value						
Opening Balance		$ -	$ 16,301	$ 32,268	$ 1,462,269	$ 1,772,021
Capital Additions during year (from Smart Meter Costs)	$ -	$ 16,301	$ 15,967	$ 1,430,001	$ 309,752	$ 115,950
Retirements/Removals (if applicable)						
Closing Balance	$ -	$ 16,301	$ 32,268	$ 1,462,269	$ 1,772,021	$ 1,887,971
Accumulated Depreciation						
Opening Balance		$ -	-$ 543	-$ 2,162	-$ 51,980	-$ 159,790
Amortization expense during year	$ -	-$ 543	-$ 1,619	-$ 49,818	-$ 107,810	-$ 122,000
Retirements/Removals (if applicable)						
Closing Balance	$ -	-$ 543	-$ 2,162	-$ 51,980	-$ 159,790	-$ 281,790
Net Book Value						
Opening Balance	$ -	$ -	$ 15,758	$ 30,106	$ 1,410,289	$ 1,612,231
Closing Balance	$ -	$ 15,758	$ 30,106	$ 1,410,289	$ 1,612,231	$ 1,606,181
Average Net Book Value	$ -	$ 7,879	$ 22,932	$ 720,197	$ 1,511,260	$ 1,609,206
Net Fixed Assets - Computer Hardware						
Gross Book Value						
Opening Balance		$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)						
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation						
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)						
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value						
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -
Net Fixed Assets - Computer Software (including Applications Software)						
Gross Book Value						
Opening Balance		$ -	$ -	$ -	$ 32,533	$ 32,533
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 32,533	$ -	$ -
Retirements/Removals (if applicable)						
Closing Balance	$ -	$ -	$ -	$ 32,533	$ 32,533	$ 32,533
Accumulated Depreciation						
Opening Balance	$ -	$ -	$ -	$ -	-$ 5,422	-$ 16,267
Amortization expense during year	$ -	$ -	$ -	-$ 5,422	-$ 10,844	-$ 10,844
Retirements/Removals (if applicable)						
Closing Balance	$ -	$ -	$ -	-$ 5,422	-$ 16,267	-$ 27,111
Net Book Value						
Opening Balance	$ -	$ -	$ -	$ -	$ 27,111	$ 16,267
Closing Balance	$ -	$ -	$ -	$ 27,111	$ 16,267	$ 5,422
Average Net Book Value	$ -	$ -	$ -	$ 13,555	$ 21,689	$ 10,844

Net Fixed Assets - Tools and Equipment

Gross Book Value						
Opening Balance		$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)						
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation						
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)						
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value						
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -

Net Fixed Assets - Other Equipment

Gross Book Value						
Opening Balance		$ -	$ -	$ -	$ 274,110	$ 274,310
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 274,110	$ 200	$ -
Retirements/Removals (if applicable)						
Closing Balance	$ -	$ -	$ -	$ 274,110	$ 274,310	$ 274,310
Accumulated Depreciation						
Opening Balance	$ -	$ -	$ -	$ -	-$ 6,853	-$ 20,563
Amortization expense during year	$ -	$ -	$ -	-$ 6,853	-$ 13,711	-$ 13,716
Retirements/Removals (if applicable)						
Closing Balance	$ -	$ -	$ -	-$ 6,853	-$ 20,563	-$ 34,279
Net Book Value						
Opening Balance	$ -	$ -	$ -	$ -	$ 267,257	$ 253,747
Closing Balance	$ -	$ -	$ -	$ 267,257	$ 253,747	$ 240,031
Average Net Book Value	$ -	$ -	$ -	$ 133,629	$ 260,502	$ 246,889

2012 and later
$ 1,887,971
$ -
$ 1,887,971
-$ 281,790
-$ 125,865
-$ 407,654
$ 1,606,181
$ 1,480,317
$ 1,543,249
$ -
$ -
$ -
$ -
$ -
$ -
$ -
$ -
$ -
$ 32,533
$ -
$ 32,533
-$ 27,111
-$ 5,422
-$ 32,533
$ 5,422
$ -
$ 2,711

$	-
$	-
$	-
$	-
$	-
$	-
$	-
$	-
$	-
$	274,310
$	-
$	274,310
-$	34,279
-$	13,716
-$	47,994
$	240,031
$	226,316
$	233,174

Ontario Energy Board

Smart Meter Model

Innisfil Hydro Distribution Systems Limited

	2006	2007	2008	2009	2010	2011	2012 and Later
Average Net Fixed Asset Values (from Sheet 4)							
Smart Meters	$ -	$ 7,879	$ 22,932	$ 720,197	$ 1,511,260	$ 1,609,206	$ 1,543,249
Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software	$ -	$ -	$ -	$ 13,555	$ 21,689	$ 10,844	$ 2,711
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ 133,629	$ 260,502	$ 246,889	$ 233,174
Total Net Fixed Assets	**$ -**	**$ 7,879**	**$ 22,932**	**$ 867,381**	**$ 1,793,451**	**$ 1,866,940**	**$ 1,779,134**
Working Capital							
Operating Expenses (from Sheet 2)	$ -	$ -	$ -	$ 39,924	$ 103,440	$ 241,561	$ 78,800
Working Capital Factor (from Sheet 3)	15%	15%	15%	15%	15%	15%	15%
Working Capital Allowance	$ -	$ -	$ -	$ 5,989	$ 15,516	$ 36,234	$ 11,820
Incremental Smart Meter Rate Base	**$ -**	**$ 7,879**	**$ 22,932**	**$ 873,370**	**$ 1,808,967**	**$ 1,903,174**	**$ 1,790,954**
Return on Rate Base							
Capital Structure							
Deemed Short Term Debt	$ -	$ -	$ 917	$ 34,935	$ 72,359	$ 76,127	$ 71,638
Deemed Long Term Debt	$ -	$ 3,939	$ 11,305	$ 460,266	$ 1,013,021	$ 1,065,777	$ 1,002,934
Equity	$ -	$ 3,939	$ 10,709	$ 378,169	$ 723,587	$ 761,269	$ 716,381
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capitalization	$ -	$ 7,879	$ 22,932	$ 873,370	$ 1,808,967	$ 1,903,174	$ 1,790,954
Return on							
Deemed Short Term Debt	$ -	$ -	$ 84	$ 465	$ 962	$ 1,012	$ 953
Deemed Long Term Debt	$ -	$ 246	$ 1,039	$ 33,507	$ 73,748	$ 77,589	$ 73,014
Equity	$ -	$ 355	$ 964	$ 30,291	$ 57,959	$ 60,978	$ 57,382
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Return on Capital	$ -	$ 601	$ 2,087	$ 64,263	$ 132,670	$ 139,579	$ 131,349
Operating Expenses	$ -	$ -	$ -	$ 39,924	$ 103,440	$ 241,561	$ 78,800
Amortization Expenses (from Sheet 4)							
Smart Meters	$ -	$ 543	$ 1,619	$ 49,818	$ 107,810	$ 122,000	$ 125,865
Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software	$ -	$ -	$ -	$ 5,422	$ 10,844	$ 10,844	$ 5,422
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ 6,853	$ 13,711	$ 13,716	$ 13,716
Total Amortization Expense in Year	$ -	$ 543	$ 1,619	$ 62,093	$ 132,365	$ 146,560	$ 145,002
Incremental Revenue Requirement before Taxes/PILs	$ -	$ 1,144	$ 3,706	$ 166,280	$ 368,474	$ 527,699	$ 355,151
Calculation of Taxable Income							
Incremental Operating Expenses	$ -	$ -	$ -	$ 39,924	$ 103,440	$ 241,561	$ 78,800
Amortization Expense	$ -	$ 543	$ 1,619	$ 62,093	$ 132,365	$ 146,560	$ 145,002
Interest Expense	$ -	$ 246	$ 1,123	$ 33,972	$ 74,710	$ 78,601	$ 73,966
Net Income for Taxes/PILs	$ -	$ 355	$ 964	$ 30,291	$ 57,959	$ 60,978	$ 57,382
Grossed-up Taxes/PILs (from Sheet 7)	$ -	$ 174.48	$ 416.43	$ 18,391.33	$ 28,397.82	$ 28,102.21	$ 25,996.97
Revenue Requirement, including Grossed-up Taxes/PILs	$ -	$ 1,319	$ 4,122	$ 184,671	$ 396,872	$ 555,802	$ 381,148

For PILs Calculation

UCC - Smart Meters	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ 15,648.96	$ 29,725.36	$ 1,400,148.29	$ 1,585,498.35	$ 1,569,970.48
Capital Additions	$ -	$ 16,301.00	$ 15,967.00	$ 1,430,001.00	$ 309,752.00	$ 115,950.00	$ -
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ 16,301.00	$ 31,615.96	$ 1,459,726.36	$ 1,709,900.29	$ 1,701,448.35	$ 1,569,970.48
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 8,150.50	$ 7,983.50	$ 715,000.50	$ 154,876.00	$ 57,975.00	$ -
Reduced UCC	$ -	$ 8,150.50	$ 23,632.46	$ 744,725.86	$ 1,555,024.29	$ 1,643,473.35	$ 1,569,970.48
CCA Rate Class	47	47	47	47	47	47	47
CCA Rate	8%	8%	8%	8%	8%	8%	8%
CCA	$ -	$ 652.04	$ 1,890.60	$ 59,578.07	$ 124,401.94	$ 131,477.87	$ 125,597.64
Closing UCC	$ -	$ 15,648.96	$ 29,725.36	$ 1,400,148.29	$ 1,585,498.35	$ 1,569,970.48	$ 1,444,372.84

UCC - Computer Equipment	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ 29,279.70	$ 23,423.76	$ 18,739.01
Capital Additions Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Computer Software	$ -	$ -	$ -	$ 32,533.00	$ -	$ -	$ -
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ -	$ -	$ 32,533.00	$ 29,279.70	$ 23,423.76	$ 18,739.01
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ 16,266.50	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ 16,266.50	$ 29,279.70	$ 23,423.76	$ 18,739.01
CCA Rate Class	8	8	8	8	8	8	8
CCA Rate	20%	20%	20%	20%	20%	20%	20%
CCA	$ -	$ -	$ -	$ 3,253.30	$ 5,855.94	$ 4,684.75	$ 3,747.80
Closing UCC	$ -	$ -	$ -	$ 29,279.70	$ 23,423.76	$ 18,739.01	$ 14,991.21

UCC - General Equipment	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ 274,110.00	$ 274,310.00	$ 274,310.00
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ 274,110.00	$ 200.00	$ -	$ -
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ -	$ -	$ 274,110.00	$ 274,310.00	$ 274,310.00	$ 274,310.00
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ 137,055.00	$ 100.00	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ 137,055.00	$ 274,210.00	$ 274,310.00	$ 274,310.00
CCA Rate Class	0	0	0	0	0	0	0
CCA Rate	0%	0%	0%	0%	0%	0%	0%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ 274,110.00	$ 274,310.00	$ 274,310.00	$ 274,310.00

Ontario Energy Board

Smart Meter Model

Innisfil Hydro Distribution Systems Limited

PILs Calculation

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
INCOME TAX							
Net Income	$ -	$ 354.55	$ 963.82	$ 30,291.35	$ 57,959.29	$ 60,977.69	$ 57,382.15
Amortization	$ -	$ 543.37	$ 1,618.97	$ 62,092.82	$ 132,364.50	$ 146,559.57	$ 145,002.40
CCA - Smart Meters	$ -	-$ 652.04	-$ 1,890.60	-$ 59,578.07	-$ 124,401.94	-$ 131,477.87	-$ 125,597.64
CCA - Computers	$ -	$ -	$ -	-$ 3,253.30	-$ 5,855.94	-$ 4,684.75	-$ 3,747.80
CCA - Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA - Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Change in taxable income	$ -	$ 245.87	$ 692.19	$ 29,552.80	$ 60,065.91	$ 71,374.63	$ 73,039.11
Tax Rate (from Sheet 3)	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%
Income Taxes Payable	$ -	$ 88.81	$ 231.88	$ 9,752.42	$ 18,620.43	$ 20,163.33	$ 19,172.77
ONTARIO CAPITAL TAX							
Smart Meters	$ -	$ 15,757.63	$ 30,105.67	$ 1,410,288.77	$ 1,612,231.10	$ 1,606,181.37	$ 1,480,316.63
Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software (Including Application Software)	$ -	$ -	$ -	$ 27,110.83	$ 16,266.50	$ 5,422.17	$ -
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ 267,257.25	$ 253,746.75	$ 240,031.25	$ 226,315.75
Rate Base	$ -	$ 15,757.63	$ 30,105.67	$ 1,704,656.85	$ 1,882,244.35	$ 1,851,634.78	$ 1,706,632.38
Less: Exemption							
Deemed Taxable Capital	$ -	$ 15,757.63	$ 30,105.67	$ 1,704,656.85	$ 1,882,244.35	$ 1,851,634.78	$ 1,706,632.38
Ontario Capital Tax Rate (from Sheet 3)	0.300%	0.225%	0.225%	0.225%	0.075%	0.000%	0.000%
Net Amount (Taxable Capital x Rate)	$ -	$ 35.45	$ 67.74	$ 3,835.48	$ 1,411.68	$ -	$ -
Change in Income Taxes Payable	$ -	$ 88.81	$ 231.88	$ 9,752.42	$ 18,620.43	$ 20,163.33	$ 19,172.77
Change in OCT	$ -	$ 35.45	$ 67.74	$ 3,835.48	$ 1,411.68	$ -	$ -
PILs	$ -	$ 124.26	$ 299.62	$ 13,587.90	$ 20,032.11	$ 20,163.33	$ 19,172.77
Gross Up PILs							
Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%
Change in Income Taxes Payable	$ -	$ 139.03	$ 348.70	$ 14,555.85	$ 26,986.13	$ 28,102.21	$ 25,996.97
Change in OCT	$ -	$ 35.45	$ 67.74	$ 3,835.48	$ 1,411.68	$ -	$ -
PILs	**$ -**	**$ 174.48**	**$ 416.43**	**$ 18,391.33**	**$ 28,397.82**	**$ 28,102.21**	**$ 25,996.97**

Innisfil Hydro Distribution Systems Limited

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1		
2006 Q2	4.14%	4.68%
2006 Q3	4.59%	5.05%
2006 Q4	4.59%	4.72%
2007 Q1	4.59%	4.72%
2007 Q2	4.59%	4.72%
2007 Q3	4.59%	5.18%
2007 Q4	5.14%	5.18%
2008 Q1	5.14%	5.18%
2008 Q2	4.08%	5.18%
2008 Q3	3.35%	5.43%
2008 Q4	3.35%	5.43%
2009 Q1	2.45%	6.61%
2009 Q2	1.00%	6.61%
2009 Q3	0.55%	5.67%
2009 Q4	0.55%	4.66%
2010 Q1	0.55%	4.34%
2010 Q2	0.55%	4.34%
2010 Q3	0.89%	4.66%
2010 Q4	1.20%	4.01%
2011 Q1	1.47%	4.29%
2011 Q2	1.47%	4.29%
2011 Q3	1.47%	4.29%
2011 Q4	1.47%	4.29%
2012 Q1	1.47%	4.29%
2012 Q2	1.47%	4.29%
2012 Q3	1.47%	4.29%
2012 Q4	1.47%	4.29%

Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts
Jan-06	2006	Q1	$ -		0.00%	$ -	$ -	
Feb-06	2006	Q1	$ -		0.00%	$ -	$ -	
Mar-06	2006	Q1	$ -		0.00%	$ -	$ -	
Apr-06	2006	Q2	$ -		4.14%	$ -	$ -	
May-06	2006	Q2	$ -	$ 277.00	4.14%	$ -	$ 277.00	
Jun-06	2006	Q2	$ 277.00	$ 3,106.00	4.14%	$ 0.96	$ 3,383.96	
Jul-06	2006	Q3	$ 3,383.00	$ 3,855.00	4.59%	$ 12.94	$ 7,250.94	
Aug-06	2006	Q3	$ 7,238.00	$ 3,857.00	4.59%	$ 27.69	$ 11,122.69	
Sep-06	2006	Q3	$ 11,095.00	$ 3,847.00	4.59%	$ 42.44	$ 14,984.44	
Oct-06	2006	Q4	$ 14,942.00	$ 3,859.00	4.59%	$ 57.15	$ 18,858.15	
Nov-06	2006	Q4	$ 18,801.00	$ 3,860.00	4.59%	$ 71.91	$ 22,732.91	
Dec-06	2006	Q4	$ 22,661.00	$ 3,869.00	4.59%	$ 86.68	$ 26,616.68	$ 26,829.77
Jan-07	2007	Q1	$ 26,530.00	$ 3,867.00	4.59%	$ 101.48	$ 30,498.48	
Feb-07	2007	Q1	$ 30,397.00	$ 3,877.00	4.59%	$ 116.27	$ 34,390.27	
Mar-07	2007	Q1	$ 34,274.00	$ 3,875.00	4.59%	$ 131.10	$ 38,280.10	
Apr-07	2007	Q2	$ 38,149.00	$ 3,881.00	4.59%	$ 145.92	$ 42,175.92	
May-07	2007	Q2	$ 42,030.00	$ 3,878.00	4.59%	$ 160.76	$ 46,068.76	
Jun-07	2007	Q2	$ 45,908.00	$ 3,890.00	4.59%	$ 175.60	$ 49,973.60	
Jul-07	2007	Q3	$ 49,798.00	$ 3,884.00	4.59%	$ 190.48	$ 53,872.48	
Aug-07	2007	Q3	$ 53,682.00	$ 3,887.00	4.59%	$ 205.33	$ 57,774.33	
Sep-07	2007	Q3	$ 57,569.00	$ 3,897.00	4.59%	$ 220.20	$ 61,686.20	
Oct-07	2007	Q4	$ 61,466.00	$ 3,898.00	5.14%	$ 263.28	$ 65,627.28	
Nov-07	2007	Q4	$ 65,364.00	$ 3,906.00	5.14%	$ 279.98	$ 69,549.98	
Dec-07	2007	Q4	$ 69,270.00	$ 3,915.00	5.14%	$ 296.71	$ 73,481.71	$ 48,942.11
Jan-08	2008	Q1	$ 73,185.00	$ 3,926.00	5.14%	$ 313.48	$ 77,424.48	
Feb-08	2008	Q1	$ 77,111.00	$ 3,933.00	5.14%	$ 330.29	$ 81,374.29	
Mar-08	2008	Q1	$ 81,044.00	$ 3,936.00	5.14%	$ 347.14	$ 85,327.14	
Apr-08	2008	Q2	$ 84,980.00	$ 3,932.00	4.08%	$ 288.93	$ 89,200.93	
May-08	2008	Q2	$ 88,912.00	$ 3,939.00	4.08%	$ 302.30	$ 93,153.30	
Jun-08	2008	Q2	$ 92,851.00	$ 3,960.00	4.08%	$ 315.69	$ 97,126.69	
Jul-08	2008	Q3	$ 96,811.00	$ 3,973.00	3.35%	$ 270.26	$ 101,054.26	
Aug-08	2008	Q3	$ 100,784.00	$ 3,968.00	3.35%	$ 281.36	$ 105,033.36	
Sep-08	2008	Q3	$ 104,752.00	$ 3,989.00	3.35%	$ 292.43	$ 109,033.43	
Oct-08	2008	Q4	$ 108,741.00	$ 3,996.00	3.35%	$ 303.57	$ 113,040.57	
Nov-08	2008	Q4	$ 112,737.00	$ 4,010.00	3.35%	$ 314.72	$ 117,061.72	
Dec-08	2008	Q4	$ 116,747.00	$ 4,008.00	3.35%	$ 325.92	$ 121,080.92	$ 51,256.09
Jan-09	2009	Q1	$ 120,755.00	$ 4,024.00	2.45%	$ 246.54	$ 125,025.54	
Feb-09	2009	Q1	$ 124,779.00	$ 4,028.00	2.45%	$ 254.76	$ 129,061.76	
Mar-09	2009	Q1	$ 128,807.00	$ 4,032.00	2.45%	$ 262.98	$ 133,101.98	
Apr-09	2009	Q2	$ 132,839.00	$ 4,046.00	1.00%	$ 110.70	$ 136,995.70	
May-09	2009	Q2	$ 136,885.00	$ 4,812.00	1.00%	$ 114.07	$ 141,811.07	
Jun-09	2009	Q2	$ 141,697.00	$ 12,544.00	1.00%	$ 118.08	$ 154,359.08	
Jul-09	2009	Q3	$ 154,241.00	$ 14,457.00	0.55%	$ 70.69	$ 168,768.69	
Aug-09	2009	Q3	$ 168,698.00	$ 14,472.00	0.55%	$ 77.32	$ 183,247.32	
Sep-09	2009	Q3	$ 183,170.00	$ 14,468.00	0.55%	$ 83.95	$ 197,721.95	
Oct-09	2009	Q4	$ 197,638.00	$ 14,500.00	0.55%	$ 90.58	$ 212,228.58	
Nov-09	2009	Q4	$ 212,138.00	$ 14,519.00	0.55%	$ 97.23	$ 226,754.23	
Dec-09	2009	Q4	$ 226,657.00	$ 14,492.00	0.55%	$ 103.88	$ 241,252.88	$ 122,024.78
Jan-10	2010	Q1	$ 241,149.00	$ 14,544.00	0.55%	$ 110.53	$ 255,803.53	
Feb-10	2010	Q1	$ 255,693.00	$ 14,557.00	0.55%	$ 117.19	$ 270,367.19	
Mar-10	2010	Q1	$ 270,250.00	$ 14,515.00	0.55%	$ 123.86	$ 284,888.86	
Apr-10	2010	Q2	$ 284,765.00	$ 14,552.00	0.55%	$ 130.52	$ 299,447.52	
May-10	2010	Q2	$ 299,317.00	$ 15,938.00	0.55%	$ 137.19	$ 315,392.19	
Jun-10	2010	Q2	$ 315,255.00	$ 26,663.00	0.55%	$ 144.49	$ 342,062.49	
Jul-10	2010	Q3	$ 341,918.00	$ 29,152.00	0.89%	$ 253.59	$ 371,323.59	
Aug-10	2010	Q3	$ 371,070.00	$ 29,138.00	0.89%	$ 275.21	$ 400,483.21	
Sep-10	2010	Q3	$ 400,208.00	$ 29,238.00	0.89%	$ 296.82	$ 429,742.82	
Oct-10	2010	Q4	$ 429,446.00	$ 29,216.00	1.20%	$ 429.45	$ 459,091.45	
Nov-10	2010	Q4	$ 458,662.00	$ 29,320.00	1.20%	$ 458.66	$ 488,440.66	
Dec-10	2010	Q4	$ 487,982.00	$ 29,316.00	1.20%	$ 487.98	$ 517,785.98	$ 279,114.49
Jan-11	2011	Q1	$ 517,298.00	$ 29,410.00	1.47%	$ 633.69	$ 547,341.69	
Feb-11	2011	Q1	$ 546,708.00	$ 17,956.00	1.47%	$ 669.72	$ 565,333.72	
Mar-11	2011	Q1	$ 564,664.00	$ 29,366.00	1.47%	$ 691.71	$ 594,721.71	
Apr-11	2011	Q2	$ 594,030.00	$ 29,498.00	1.47%	$ 727.69	$ 624,255.69	
May-11	2011	Q2	$ 623,528.00	$ 29,445.00	1.47%	$ 763.82	$ 653,736.82	
Jun-11	2011	Q2	$ 652,973.00	$ 29,493.00	1.47%	$ 799.89	$ 683,265.89	
Jul-11	2011	Q3	$ 682,466.00	$ 29,458.00	1.47%	$ 836.02	$ 712,760.02	
Aug-11	2011	Q3	$ 711,924.00	$ 31,442.00	1.47%	$ 872.11	$ 744,238.11	
Sep-11	2011	Q3	$ 743,366.00	$ 28,596.50	1.47%	$ 910.62	$ 772,873.12	

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts
			Oct-11	2011	Q4	$ 771,962.50	$ 28,596.50	1.47%	$ 945.65	$ 801,504.65	
			Nov-11	2011	Q4	$ 800,559.00	$ 28,596.50	1.47%	$ 980.68	$ 830,136.18	
			Dec-11	2011	Q4	$ 829,155.50	$ 28,596.50	1.47%	$ 1,015.72	$ 858,767.72	$ 350,301.32
			Jan-12	2012	Q1	$ 857,752.00	$ 28,596.50	1.47%	$ 1,050.75	$ 887,399.25	
			Feb-12	2012	Q1	$ 886,348.50	$ 28,596.50	1.47%	$ 1,085.78	$ 916,030.78	
			Mar-12	2012	Q1	$ 914,945.00	$ 28,596.50	1.47%	$ 1,120.81	$ 944,662.31	
			Apr-12	2012	Q2	$ 943,541.50	$ 28,596.50	1.47%	$ 1,155.84	$ 973,293.84	
			May-12	2012	Q2	$ 972,138.00	$ 28,596.50	1.47%	$ 1,190.87	$ 1,001,925.37	
			Jun-12	2012	Q2	$ 1,000,734.50		1.47%	$ 1,225.90	$ 1,001,960.40	
			Jul-12	2012	Q3	$ 1,000,734.50		1.47%	$ 1,225.90	$ 1,001,960.40	
			Aug-12	2012	Q3	$ 1,000,734.50		1.47%	$ 1,225.90	$ 1,001,960.40	
			Sep-12	2012	Q3	$ 1,000,734.50		1.47%	$ 1,225.90	$ 1,001,960.40	
			Oct-12	2012	Q4	$ 1,000,734.50		1.47%	$ 1,225.90	$ 1,001,960.40	
			Nov-12	2012	Q4	$ 1,000,734.50		1.47%	$ 1,225.90	$ 1,001,960.40	
			Dec-12	2012	Q4	$ 1,000,734.50		1.47%	$ 1,225.90	$ 1,001,960.40	$ 157,167.85
			Total Funding Adder Revenues Collected				**$ 1,000,734.50**		**$ 34,901.91**	**$ 1,035,636.41**	**$ 1,035,636.41**

Board Approved Smart Meter Funding Adder (from Tariff)
$ 0.28
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Board Approved Smart Meter Funding Adder (from Tariff)
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$ 2.00
$ 2.00
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$ 2.00
$ 2.00

Innisfil Hydro Distribution Systems Limited

This worksheet calculates the interest on OM&A and amortization/depr

Account 1556 - Su

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)
2006 Q1	0.00%	0.00%	Jan-06	2006	Q1	$ -
2006 Q2	4.14%	4.68%	Feb-06	2006	Q1	-
2006 Q3	4.59%	5.05%	Mar-06	2006	Q1	-
2006 Q4	4.59%	4.72%	Apr-06	2006	Q2	-
2007 Q1	4.59%	4.72%	May-06	2006	Q2	-
2007 Q2	4.59%	4.72%	Jun-06	2006	Q2	-
2007 Q3	4.59%	5.18%	Jul-06	2006	Q3	-
2007 Q4	5.14%	5.18%	Aug-06	2006	Q3	-
2008 Q1	5.14%	5.18%	Sep-06	2006	Q3	-
2008 Q2	4.08%	5.18%	Oct-06	2006	Q4	-
2008 Q3	3.35%	5.43%	Nov-06	2006	Q4	-
2008 Q4	3.35%	5.43%	Dec-06	2006	Q4	-
2009 Q1	2.45%	6.61%	Jan-07	2007	Q1	-
2009 Q2	1.00%	6.61%	Feb-07	2007	Q1	-
2009 Q3	0.55%	5.67%	Mar-07	2007	Q1	-
2009 Q4	0.55%	4.66%	Apr-07	2007	Q2	-
2010 Q1	0.55%	4.34%	May-07	2007	Q2	-
2010 Q2	0.55%	4.34%	Jun-07	2007	Q2	-
2010 Q3	0.89%	4.66%	Jul-07	2007	Q3	-
2010 Q4	1.20%	4.01%	Aug-07	2007	Q3	-
2011 Q1	1.47%	4.29%	Sep-07	2007	Q3	-
2011 Q2	1.47%	4.29%	Oct-07	2007	Q4	-
2011 Q3	1.47%	4.29%	Nov-07	2007	Q4	-

2011 Q4	1.47%	4.29%	Dec-07	2007	Q4	-
2012 Q1	1.47%	4.29%	Jan-08	2008	Q1	-
2012 Q2	1.47%	4.29%	Feb-08	2008	Q1	-
2012 Q3	1.47%	4.29%	Mar-08	2008	Q1	-
2012 Q4	1.47%	4.29%	Apr-08	2008	Q2	-
			May-08	2008	Q2	-
			Jun-08	2008	Q2	-
			Jul-08	2008	Q3	-
			Aug-08	2008	Q3	-
			Sep-08	2008	Q3	-
			Oct-08	2008	Q4	-
			Nov-08	2008	Q4	-
			Dec-08	2008	Q4	-
			Jan-09	2009	Q1	-
			Feb-09	2009	Q1	-
			Mar-09	2009	Q1	-
			Apr-09	2009	Q2	-
			May-09	2009	Q2	-
			Jun-09	2009	Q2	-
			Jul-09	2009	Q3	-
			Aug-09	2009	Q3	-
			Sep-09	2009	Q3	-
			Oct-09	2009	Q4	-
			Nov-09	2009	Q4	-
			Dec-09	2009	Q4	-
			Jan-10	2010	Q1	-
			Feb-10	2010	Q1	-
			Mar-10	2010	Q1	-
			Apr-10	2010	Q2	-
			May-10	2010	Q2	-
			Jun-10	2010	Q2	-
			Jul-10	2010	Q3	-
			Aug-10	2010	Q3	-
			Sep-10	2010	Q3	-
			Oct-10	2010	Q4	-
			Nov-10	2010	Q4	-
			Dec-10	2010	Q4	-
			Jan-11	2011	Q1	-
			Feb-11	2011	Q1	-
			Mar-11	2011	Q1	-
			Apr-11	2011	Q2	-
			May-11	2011	Q2	-
			Jun-11	2011	Q2	-
			Jul-11	2011	Q3	-
			Aug-11	2011	Q3	-
			Sep-11	2011	Q3	-
			Oct-11	2011	Q4	-
			Nov-11	2011	Q4	-
			Dec-11	2011	Q4	-

[redacted]	Jan-12	*2012*	*Q1*	-
	Feb-12	*2012*	*Q1*	-
	Mar-12	*2012*	*Q1*	-
	Apr-12	*2012*	*Q2*	-
	May-12	*2012*	*Q2*	-
	Jun-12	*2012*	*Q2*	-
	Jul-12	*2012*	*Q3*	-
	Aug-12	*2012*	*Q3*	-
	Sep-12	*2012*	*Q3*	-
	Oct-12	*2012*	*Q4*	-
	Nov-12	*2012*	*Q4*	-
	Dec-12	*2012*	*Q4*	-

reciation expense, based on monthly data.

b-accounts Operating Expenses, Amortization Expenses, Carrying Charges

OM&A Expenses	Amortization / Depreciation Expense	Closing Balance (Principal)	(Annual) Interest Rate	Interest (on opening balance)	Cumulative Interest
		-	0.00%	-	-
		-	0.00%	-	-
		-	0.00%	-	-
		-	4.14%	-	-
		-	4.14%	-	-
		-	4.14%	-	-
		-	4.59%	-	-
		-	4.59%	-	-
		-	4.59%	-	-
		-	4.59%	-	-
		-	4.59%	-	-
		-	4.59%	-	-
		-	4.59%	-	-
		-	4.59%	-	-
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		-	4.59%	-	-
		-	4.59%	-	-
		-	4.59%	-	-
		-	4.59%	-	-
		-	5.14%	-	-
		-	5.14%	-	-

		-	5.14%	-	-
		-	5.14%	-	-
		-	5.14%	-	-
		-	5.14%	-	-
		-	4.08%	-	-
		-	4.08%	-	-
		-	4.08%	-	-
		-	3.35%	-	-
		-	3.35%	-	-
		-	3.35%	-	-
		-	3.35%	-	-
		-	3.35%	-	-
		-	3.35%	-	-
		-	2.45%	-	-
		-	2.45%	-	-
		-	2.45%	-	-
		-	1.00%	-	-
		-	1.00%	-	-
		-	1.00%	-	-
		-	0.55%	-	-
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		-	0.55%	-	-
		-	0.55%	-	-
		-	0.89%	-	-
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		-	0.89%	-	-
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		-	1.47%	-	-
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		-	1.47%	-	-
$ -	$ -	$ -			

Innisfil Hydro Distribution Systems Limited

This worksheet calculates the interest on OM&A and amortization/depreciation expen

Year	**OM&A (from Sheet 5)**	**Amortization Expense (from Sheet 5)**	**Cumulative OM&A and Amortization Expense**
2006	$ -	$ -	$ -
2007	$ -	$ 543.37	$ 543.37
2008	$ -	$ 1,618.97	$ 2,162.33
2009	$ 39,924.00	$ 62,092.82	$ 104,179.15
2010	$ 103,440.00	$ 132,364.50	$ 339,983.65
2011	$ 241,561.00	$ 146,559.57	$ 728,104.22
2012	$ 78,800.00	$ 145,002.40	$ 951,906.62

Cumulative Interest to 2011
Cumulative Interest to 2012

Ontario Energy Board

Smart Meter Model

ıse, in the absence of monthly data.

Average Cumulative OM&A and Amortization Expense	Average Annual Prescribed Interest Rate for Deferral and Variance Accounts (from Sheets 8A and 8B)	Simple Interest on OM&A and Amortization Expenses
$ -	4.37%	$ -
$ 271.68	4.73%	$ 12.84
$ 1,352.85	3.98%	$ 53.84
$ 53,170.74	1.14%	$ 604.82
$ 222,081.40	0.80%	$ 1,771.10
$ 534,043.93	1.47%	$ 7,850.45
$ 840,005.42	1.47%	$ 12,348.08
		$ 10,293.05
		$ 22,641.13

Ontario Energy Board

Smart Meter Model

Innisfil Hydro Distribution Systems Limited

This worksheet calculates the Smart Meter Disposition Rider and the Smart Meter Incremental Revenue Requirement Rate Rider, if applicable. This worksheet also calculates any new Smart Meter Funding Adder that a distributor may wish to request. However, please note that in many 2011 IRM decisions, the Board noted that current funding adders will cease on April 30, 2011 and that the Board's expectation is that distributors will file for a final review of prudence at the earliest opportunity. The Board also noted that the SMFA is a tool designed to provide advance funding and to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board. The Board observed that the SMFA was not intended to be compensatory (return on and of capital) on a cumulative basis over the term the SMFA was in effect. The SMFA was initially designed to fund future investment, and not fully fund prior capital investment. Distributors that seek a new SMFA should provide evidence to support its proposal. This would include documentation of where the distributor is with respect to its smart meter deployment program, and reasons as to why the distributor's circumstances are such that continuation of the SMFA is warranted. Press the "UPDATE WORKSHEET" button after choosing the applicable adders/riders.

Check if applicable		
	Smart Meter Funding Adder (SMFA)	
X	Smart Meter Disposition Rider (SMDR)	**The SMDR is calculated based on costs to December 31, 2011**
X	Smart Meter Incremental Revenue Requirement Rate Rider (SMIRR)	**The SMIRR is calculated based on the incremental revenue requirement associated with the recovery of capital related costs to December 31, 2012 and associated OM&A.**

	2006	2007	2008	2009	2010	2011	2012 and later	Total
Deferred and forecasted Smart Meter Incremental Revenue Requirement (from Sheet 5)	$ -	$ 1,318.61	$ 4,122.47	$ 184,671.49	$ 396,871.93	$ 555,801.53	$ 381,147.91	$ 1,523,933.94
Interest on Deferred and forecasted OM&A and Amortization Expense (Sheet 8A/8B) (Check **one** of the boxes below)	$ -	$ 12.84	$ 53.84	$ 604.82	$ 1,771.10	$ 7,850.45		$ 10,293.05
[ ] Sheet 8A (Interest calculated on monthly balances)								$ -
[X] Sheet 8B (Interest calculated on average annual balances)	$ -	$ 12.84	$ 53.84	$ 604.82	$ 1,771.10	$ 7,850.45		$ 10,293.05
SMFA Revenues (from Sheet 8)	$ 26,530.00	$ 46,655.00	$ 47,570.00	$ 120,394.00	$ 276,149.00	$ 340,454.00	$ 142,982.50	$ 1,000,734.50
SMFA Interest (from Sheet 8)	$ 299.77	$ 2,287.11	$ 3,686.09	$ 1,630.78	$ 2,965.49	$ 9,847.32	$ 14,185.35	$ 34,901.91
Net Deferred Revenue Requirement	-$ 26,829.77	-$ 47,610.66	-$ 47,079.78	$ 63,251.53	$ 119,528.53	$ 213,350.66	$ 223,980.06	$ 498,590.58
Number of Metered Customers (average for 2012 test year)							14721	

Calculation of Smart Meter Disposition Rider (per metered customer per month)

Years for collection or refunding		2
Deferred Incremental Revenue Requirement from 2006 to December 31, 2011 plus Interest on OM&A and Amortization		$ 1,153,079.08
SMFA Revenues collected from 2006 to 2012 test year (inclusive) Plus Simple Interest on SMFA Revenues		$ 1,035,636.41
Net Deferred Revenue Requirement		$ 117,442.67
SMDR	May 1, 2012 to April 30, 2014	$ 0.33
Check: Forecasted SMDR Revenues		$ 116,590.32

Match

Calculation of Smart Meter Incremental Revenue Requirement Rate Rider (per metered customer per month)

Incremental Revenue Requirement for 2012	$ 381,147.91
SMIRR	$ 2.16

Match

Check: Forecasted SMIRR Revenues	$	381,568.32

Ontario Energy Board

Smart Meter Model

Innisfil Hydro Distribution Systems Limited

Funding and Cost Recovery Mechanisms

The following table provides a summary of the three mechanisms for smart meter funding and cost recovery that the Board has established and that can be calculated by this model. The Smart Meter Funding Adder ("SMFA") was described in Guideline G-2008-0002. The Smart Meter Disposition Rider ("SMDR") and Smart Meter Incremental Revenue Requirement Rate Rider ("SMIRR") were defined by the Board in the Decision for PowerStream Inc.'s application for Smart Meter disposition [EB-2010-0209], October 1, 2010.

Title	Acronym	Description
Smart Meter Funding Adder	SMFA	• Mechanism to provide funding before and during smart meter deployment and acts to smooth the rate increases due to smart meter implementation. • First implemented in rates for May 1, 2006. • Initially established at a level of about $0.26/month per metered customer for most distributors; some utilities have had unique SMFA rates due to initial Smart Meter Implementation Plans. Distributors could subsequently apply for a standard SMFA of $1.00 per metered customer per month or a utility-specific SMFA. • SMFA revenues are tracked in a sub-account of Account 1555. Upon disposition, the SMFA revenues and simple interest are used to offset the deferred historical revenue requirement of installed smart meters plus interest on the OM&A and amortization/depreciation expenses, with the variance recovered or refunded through the SMDR. • In many 2011 EDR applications, the Board capped the SMFA at $2.50/month per metered customer. Further, the Board indicated that the SMFA would cease by April 30, 2012.
Smart Meter Disposition Rider	SMDR	• The SMDR recovers, over a specified time period, the variance between: 1) the deferred revenue requirement for the installed smart meters up to the time of disposition and interest on OM&A and depreciation/amortization expenses; and 2) the SMFA revenues collected and associated interest. • The SMDR should be calculated as a fixed monthly charge. The capital (smart meter, AMI, systems hardware and software) and operating expenses are largely fixed costs and invariant to a customer's demand, and hence should be recovered largely through fixed charges. • In many cases the SMDR has been recovered on an equal basis from all metered customer classes, although more recent decisions have dealt with class-specific disposition riders. The distributor should determine and support its proposed allocation, based on principles of cost causality and practicality.
Smart Meter Incremental Revenue Requirement Rate Rider	SMIRR	• When smart meter disposition occurs in a stand-alone application, a SMIRR is calculated as the proxy for the incremental change in the distribution rates that would have occurred if the assets and operating expenses were incorporated into the rate base and the revenue requirement. • The SMIRR is calculated as the annualized revenue requirement for the test year for the capital and operating costs for smart meters. • The SMIRR should be calculated as a fixed monthly charge, similar to the SMDR. • The allocation for the SMIRR should generally be the same as for the SMDR. • The SMIRR ceases at the time of the utility's next cost of service application when smart meter capital and operating costs are explicitly incorporated into the rate base and revenue requirement.

Cost of Service Applications

The recovery of smart meter capital and operating costs is normally approved (or denied) following a review for prudence and disposition in a cost of service proceeding. A smart meter disposition rate rider (SMDR) is used to recover the residual revenue requirement that is made up of smart meter costs up to the time of disposition plus interest on OM&A and depreciation/amortization expenses, less amounts collected through the SMFA and associated interest. The approved gross book value and accumulated depreciation of installed smart meters are then added to rate base, and the test period operating expenses are added to OM&A. This ensures the recovery of the incremental revenue requirement on a going-forward basis through base rates. Further, smart meter capital and operating costs should be reflected in the cost allocation study to ensure an appropriate allocation of costs to the various customer classes.[1]

If a distributor seeks approval for costs related to 100% smart meter deployment, any capital and operating costs for smart meters that are installed beyond the (2012) test year (i.e. for new customers) should not be recorded in Accounts 1555 and 1556.

The Board considers that rates will be fully compensatory when smart meter costs are either incorporated into base rates or recovered by means of the SMIRR. When smart meters are installed for new customers, these customers will pay rates that reflect the recovery of smart meter costs. The costs of these additional smart meter costs should be reflected in normal capital and operating accounts, akin to other normal distribution assets and costs.

Stand-alone Applications

As per *Chapter 3 of the Filing Requirements for Transmission and Distribution Applications*, issued June 22, 2011, the Board expects those distributors that are scheduled to remain on IRM to file a stand-alone application with the Board seeking final approval for smart meter related costs. When rates are adjusted in a stand-alone application, there is no re-evaluation of rate base or of the revenue requirement for the purpose of setting distribution rates. Where the Board approves smart meter capital and operating costs outside of a cost of service proceeding, a SMDR is still required. In addition, a smart meter incremental revenue requirement rate rider (SMIRR) is established to recover the prospective annualized incremental revenue requirement for the approved smart meters, until the distributor's next cost of service application. The SMIRR continues until the effective date of the distributor's next cost of service rate order, at which time assets and costs are incorporated into the rate base and revenue requirement and recovered on a going-forward basis through base rates.

As in a cost of service application, when smart meter costs are approved for 100% deployment, capital and operating costs for smart meters on a going-forward basis are no longer recorded in Accounts 1555 and 1556; instead the costs are recorded in the applicable capital or operating expense account (e.g. Account 1860 – Meters for smart meter capital assets).

Evidence to be Filed in Support of Smart Meter Cost Recovery in a Cost of Service or Stand-Alone Application

The purpose of this model is to calculate a smart meter revenue requirement from a distributor's capital and OM&A costs, and to provide one methodology for the determination of associated riders and/or adders. In addition to filing this model, distributors must provide in any application for cost recovery detailed descriptions of all costs incurred. The onus is on the distributor to support its case, and the distributor should provide any additional information necessary to understand the distributor's costs in light of its circumstances. In considering the recovery of smart meter costs, the Board also expects that a distributor will provide evidence on any operational efficiencies and cost savings that result from smart meter implementation. As an example, meter reading expenses may be reduced with the activation of remote meter reading through the AMI network for residential and small general service customers.

When applying for the recovery of smart meter costs, a distributor should ensure that historical cost information has been audited including the smart meter-related deferral account balances up to the distributor's last Audited Financial Statements. A distributor may also include historical costs that are not audited and estimated costs, corresponding to a stub period or to a forecast for the test rate year. The Board expects that the majority (i.e. 90% or more) of costs for which the distributor is seeking recovery will be audited. In all cases, the Board expects that the distributor will document and explain any differences between unaudited or forecasted amounts and audited costs.

Costs Beyond Minimum Functionality

While authorized smart meter deployment must meet the requirements for minimum functionality, a distributor may incur costs that are beyond the "minimum functionality". To date, the Board has reviewed three types of costs that are "beyond minimum functionality":

A. Costs for technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06;

B. Costs for deployment of smart meters to customers other than residential and small general service (i.e. Residential and GS < 50 kW customers); and

C. Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.

Costs beyond minimum functionality for which recovery is sought must be recorded in the Smart Meter Costs tab of the model in these three categories, and appropriate supporting evidence for each cost type must be provided in the application. Further comments on each of these cost types are provided below.

A. Costs for technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg. 425/06

O.Reg. 425/06 specifies that costs that exceed minimum functionality may be approved by the Board for recovery. In deciding whether technical capabilities of installed smart meters or associated communications or other infrastructure that exceed minimum functionality are recoverable, the Board will consider the benefits of the added technical features and the prudence of these costs. Any distributor seeking recovery for these additional capabilities should provide documentation of the additional technical capabilities, the reasons for them and a detailed cost/benefit analysis.

Technical functionality beyond minimum functionality was dealt with by the Board with respect to Hydro One Networks' 2008 cost of service application, regarding the costs and benefits of super-capacitors in the smart meters and AMI collectors. In its Decision and Order on that application (EB-2007-0681), issued December 18, 2008, the Board approved the recovery of the incremental costs.

B. Costs for deployment of smart meters to customers other than residential and small general service

O.Reg. 425/06 defines smart meter deployment as pertaining to residential and small general service customers. The Functional Specification sets the required minimum level of functionality for the AMI to be "for residential and small general service consumers where the metering of demand is not required." As such, minimum functionality has been defined as customers in the residential and general service ("GS") < 50 kW classes.

While some customers in other metered customer classes (GS > 50 kW, Intermediate, Large Use) have interval meters that measure peak demand in a time interval, some distributors may have customers in these classes that have conventional meters and are not eligible for the regulated price plan ("RPP") and therefore are subject to the weighted average spot market price.

A distributor may, as part of its smart meter deployment program, decide to install smart meters for these customers. This could be on the basis that these customers will have higher demand than will typical residential and GS < 50 kW customers, and providing them with better information on how much and when they consume electricity may provide these customers with opportunities for more energy conservation and load shifting. While such meter conversions may generally appear to be logical, they are outside of the regulation and hence are beyond minimum functionality. In other instances, a distributor may convert the meters of interval-metered customers upon repair or re-sealing to "smart" meters that communicate using the AMI infrastructure that the distributor has installed, replacing the existing communications systems for these meters. Again, as these are for meters for customers other than residential and small general service, they are outside of the regulation and hence beyond minimum functionality.

The Board, as part of the Combined Proceeding (EB-2007-0063, December 13, 2007), approved cost recovery for meter conversions for GS > 50 kW customers for both Toronto Hydro Electric System Limited ("Toronto Hydro") and Hydro Ottawa Limited. However the Board stated:

"*The Board is explicitly not finding that the costs associated with these meters fall into the minimum functionality costs. The Board approval of these costs is ancillary to the smart meter decision."*

With respect to Toronto Hydro, the Board subsequently approved the recovery of these costs for smart meter installation/conversion for GS > 50 kW customers in Toronto Hydro's 2008-2009 [EB-2007-0681] and 2011 [EB-2010-0142] cost of service rate applications.

Some distributors may be doing "smart meter" conversions for General Service > 50 kW customers upon repair or resealing to enable meter data collection through the AMI infrastructure. While it is recognized that these smart meter installations and conversions are "beyond minimum functionality", a distributor may apply for the recovery of such costs. The application should document the nature, the justification and the cost per meter separately from those for the residential and GS < 50 kW customers.

C. Costs for TOU rate implementation, CIS system upgrades, web presentation, etc.

Costs for CIS systems, TOU rate implementation, etc., are beyond minimum functionality as established by the Board in the Combined Proceeding. However, such costs may be recoverable. In its application, a distributor should show how these costs are required for its smart meter program. Further, a distributor should document how these costs are incremental. For example, if a distributor has a normal budget for maintenance of its billing and CIS systems, costs claimed for system maintenance and upgrades must be shown to be incremental to the normal budget that is already recovered in base rates.

All costs beyond minimum functionality should be clearly identified and supported. Costs that are for meter data functions that will be the responsibility of the Smart Metering Entity will not be recoverable, unless already allowed for as per O.Reg. 426/06. Costs for other matters such as CIS changes or TOU bill presentment may be recoverable, but the distributor will have to support these costs and will have to demonstrate how they are required for the smart meter deployment program and that they are incremental to the distributor's normal operating costs.

Cost recovery for ongoing costs of the Smart Metering Entity should not be included in any smart meter cost recovery application, until such time as the Board establishes a cost recovery mechanism. To date, the Board has disallowed requests for either cost recovery or the establishment of a deferral account to track these costs.

Cost Allocation

The model does not deal with allocations between customer rate classes. In calculating the SMDR and SMIRR, the Board has approved, in some applications, the recovery of amounts from certain applicable customer classes based on the availability of detailed data at the customer class level and on principles of cost causality.

If a distributor does not have sufficient information to support an allocation to the applicable classes, a distributor may choose to propose a recovery on the basis of all metered customers resulting in one uniform rate rider for all metered customer classes. The model calculates the SMFA, SMIRR and SMDR on this basis.

Whichever method is adopted, the Board is of the view that any cost allocation approach should be consistent between the SMDR and the SMIRR when disposition is sought in a stand-alone application. The Board will entertain proposals supported by analysis for SMDRs and SMIRRs based on principles of cost causality and where the distributor has the necessary historical and forecasted data. Distributors should refer to the PowerStream application considered under EB-2010-0209 for a practical approach. However, if a distributor decides to adopt this approach in its application, it will have to adjust it to its own circumstances.[2] Further, adoption of this approach will not predetermine its approval by the Board in an individual application.

Stranded Meters

The model does not address the recovery of stranded meter costs. Distributors filing Cost of Service applications should refer to *Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*, issued June 22, 2011 (Section 2.5.1.5).

While it would be preferable, conceptually, to also deal with stranded meter costs in a non-cost of service application, the Board recognizes that practical difficulties would arise since there is no restatement of rate base and rates. The Board therefore expects that stranded meter costs will be left in rate base until the distributor's next cost of service application.

The Stranded Meter Rate Rider to recover the residual Net Book Value of stranded (i.e. replaced conventional) meters is separate from any SMDR or SMIRR. In other words, a distributor must calculate (and should show its derivation) the Stranded Meter Rate Rider on a stand-alone basis.

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[1] See Section 2.10 – Cost Allocation of Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, issued June 22, 2011.
[2] For example, if a distributor has deployed smart meters to classes other than Residential and GS < 50 kW, it will have to reflect the additional classes in any cost allocation proposal.

util-assist

utility strategic operational assistance

CornerstonE
Hydro Electric Concepts

Cornerstone Hydro Electric Concepts

August 15, 2011

Prepared By:
James Douglas

125 Don Hillock Drive, Unit 12
Aurora, Ontario L4G 0H8

(t) 905.967.0770 ext. 201
(e) jdouglas@util-assist.com
(w) www.util-assist.com

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Util-Assist Inc. | 125 Don Hillock Drive, Unit 12
Aurora, Ontario L4G 0H8 | [t] 905.726.7771
[f] 905.726.9655 | www.util-assist.com

Executive Summary

In June of 2004, the Minister of Energy issued a Directive under Section 27.1 of the *Ontario Energy Board Act,* 1998 which required the Board to develop and, upon approval by the Minister of Energy, implement a plan to achieve the government's objectives for the deployment of smart electricity meters. In conjunction with the development of its implementation plan, the Directive also required the Board to examine the need for and effectiveness of time of use rates for non-commodity charges - in addition to season/time-based standard supply service commodity rates the Board is already in a position to establish - to complement the implementation of and maximize the benefits of smart meters.

The provincial Smart Meter Initiative would stem from this Directive and all Local Distribution Companies (LDCs) in Ontario would be heavily involved in creating a conservation culture in Ontario and making the Province a North American leader in energy efficiency. Key initiatives included the introduction of flexible, time-of-use pricing for electricity, and a targeted reduction in Ontario's energy consumption of 5%.

The provincial initiative mandated the installation of a smart electricity meter in every Ontario home by December 31, 2010, with the interim goal of 800,000 meters being deployed by December 31, 2007. The underlying premise behind the mandate to install these meters was to educate customers on their consumption habits and to implement new rate structures that encouraged load shifting and conservation of energy, thereby reducing the requirement for increased power generation capabilities.

This was an enormous undertaking for all LDCs; a project that took months of planning and carefully managed execution. To accommodate the needs of the Ministry of Energy and Infrastructure, CHEC members installed approximately 110,000 meters to fulfill their requirements for the mandate. Combined with the magnitude of the metering project, members also had the challenge of choosing technologies and installation service providers that could accommodate the stated requirements within their diverse LDC service territories.

Other Ontario Regulations that applied to the initiative include:

Reg. 425/06 Criteria and Requirements For Meters and Metering Equipment, Systems and Technology
Reg. 426/06 Smart Meter: Costs Recovery
Reg. 427/06 Smart Meters: Discretionary Metering Activity and Procurement Principles
Reg. 235/08 Amending Reg. 427/06 Smart Meters: Discretionary Metering Activity and Procurement Principles Functional Specification for an Advanced Metering Infrastructure – July 5, 2007

Util-Assist Inc. | 125 Don Hillock Drive, Unit 12
Aurora, Ontario L4G 0H8 | [t] 905.726.7771
[f] 905.726.9655 | www.util-assist.com

Education and Preparation for the Initiative

As indicated above, the SMI required preparation and execution for the selection and deployment of new technology on an unprecedented scale. As this initiative was new to Ontario utilities, the CHEC group members recognized that there was much to be learned about the new AMI technologies to ensure that the operational efficiencies that become available through AMI would be realized as part of the initiative.

CHEC member utilities had achieved great success when working together on previous initiatives and elected for a collaborative approach to the education required for a successful Smart Meter Implementation. In so doing, utilities were involved with the Ontario Utility Smart Metering (OUSM) working group starting with its inception in March of 2005. Through this involvement, much was learned regarding prominent AMI systems and the technologies associated with back office integration of meter data, as well as the vendors associated with the installation of these products.

OUSM Working Group Participation

To satisfy the due diligence requirements of a project of this magnitude, an all-inclusive process was undertaken. In order to become educated on all aspects of the AMI initiative, CHEC members maintained involvement in the Ontario Utilities Smart Meter (OUSM), a working group that consisted of over 50 utility members that came together in an educational effort.

CHEC members supported the concept of the OUSM from the outset, embracing the collaborative approach to acquiring the required education for a successful Smart Meter Implementation. Through their involvement much was learned regarding all prominent AMI technologies available to the North American marketplace by:

1. Sharing information on the success of AMI pilots installed in utilities across the province

2. Reporting on the testing of different AMI technologies and components related to the AMI initiative which was completed in 2005.

    a. Standard Test Scripts were created and used for testing all AMI technologies, helping to provide comfort and back-up documentation to justify future vendor selection to a utility's board members and the OEB.

    b. The testing of products ensured an understanding not only of the functionality of the products *available* in this market, but also to understand the functionality that would be *required* of the different components of the Smart Meter system in order to accomplish the needs of the regulators. Acquiring insight into how different products delivered such components as time stamping of intervals, synchronization of register reads, network diagnostic components, etc, ensured that the chosen products could deliver the requirements of the regulators as well as accomplish the unique requirements of individual members.

c. The following AMI Systems were part of the testing completed by the OUSM and detailed reports are available on the Util-Assist Web Portal which provides test results and detailed information regarding functionality.

OUSM Tested AMI Systems

Elster	**Tantalus**	**EKA Systems**	**Trilliant**	**Cellnet**
Sensus	**Itron**	**SilverSpring**	**Quadlogic**	**SmartSynch**

By acting collaboratively with the OUSM, CHEC members were able to gain an understanding of the base functionality and advanced feature sets of these installed products, as well as the other prominent technologies available to the North American market.

CHEC Strategy

To cost-effectively plan for the deployment, and ensure due diligence was accommodated, CHEC members came together, and through a concerted effort, examined the benefits of a collaborative approach to planning, as well as procurement of AMI and Installation services. As part of this plan, the CHEC member utilities retained the services of Util-Assist Inc., an Ontario consulting firm who would provide guidance and direction to the group to assist in the preparation, deployment and back office integration for the SMI.

Satisfying CHEC's due diligence requirements entailed an all-encompassing process, accounting for:

1. Planning
2. Implementation
3. Testing, and
4. Complete Back Office Integration.

CHEC members worked together throughout the initiative, taking full advantage of the benefits that collaboration brings. The SMI project would touch every department in the utility and would touch every residential and small commercial customer in each LDC's service territory. All tasks had to be considered, from the selection and installation of the AMI infrastructure right down to the disposal of the redundant meters and ensuring that the recycling vendors were engaged so as to divert the meters from landfills. Benefits were found in on-going operational costs. By working together, the CHEC members drastically reduced the labour components associated with maintaining the health of the installed network, as well as the daily data collection requirements for the deployed system (i.e. 3 employees to maintain a CHEC AMI system vs. 13 employees to maintain an AMI system for each individual CHEC member).

Util-Assist Inc. | 125 Don Hillock Drive, Unit 12 Aurora, Ontario L4G 0H8 | [t] 905.726.7771 [f] 905.726.9655 | www.util-assist.com

By collaborating with Util-Assist to develop an extensive plan, CHEC Members were sufficiently prepared to accommodate the established timelines. A project of this magnitude is not without risk and within this document we have identified the potential problems and risks which may impede progress (Rate Recovery, Meter Base Repairs, etc).

All aspects of the deployment were considered, including:

1. Rate recovery,
2. Regulatory requirements regarding AMI functionality
3. Strategic planning to minimize costs for deployment
4. Audit tools during deployment
5. Back office integration
6. Meter disposal
7. AMI security
8. WEB presentment
9. Sub-metering
10. Coordination with local municipalities
11. Change management and
12. most importantly, the continued dedication to Health and Safety;

Throughout the initiative, CHEC members stayed focused on mitigating associated risks, thereby ensuring the successful implementation of the Smart Meter Initiative.

Following is a brief timeline demonstrating the order of events that the CHEC group followed:

Timeline

1. 2007: Participation in Ministry of Energy and Infrastructure authorized London Hydro AMI RFP process (establishing best practice procurement procedures).
2. Q4 2008: release of ODS provider RFP (December 12, 2008)
3. Q4 2008: vendor submittal due date for responses to ODS RFP
4. Q4 2008: release of WAN provider RFP
5. Q1 2009: release of Meter Disposal RFQ
6. Q1 2009: vendor submittal due date for responses to WAN RFP (January 2, 2009)
7. Q4 2008: release of Installation Service Provider RFP
8. Q4 2008: vendor submittal due date for responses to RFP (November 21, 2008)
9. Q4 2008: evaluation of Installation vendor submittals
10. Q1 2009: vendor negotiation (secure best pricing, discuss associated risk)
11. Q1 2009: commence deployment of residential Smart Meters

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AMI Selection Process

As mass deployment rapidly approached, the strategy of the CHEC group was to work together and create a process that accomplished the goals of the Smart Meter Initiative, while controlling the risks to customers and share holders.

The phase one approved processes included the Coalition of Large Distributors (CLD) RFPQ in conjunction with the MOE and the Hydro One procurement process, through this process, 13 utilities would be authorized to move forward with the procurement and installation of smart meters.

The remaining LDCs in Ontario would be part of the consortium of utilities working together as part of the authorized London Hydro AMI RFP process (phase two) that is summarized below.

London Hydro Phase Two AMI RFP Process Summary

- A Request for Proposal procurement transaction was conducted by London Hydro Inc., as the lead sponsoring Local Distribution Company (LDC) and with a consortia of another 63 LDCs, during the period August 2007 to July, 2008;

- The evaluation and selection phase of the RFP provided for the determination of the #1 and #2 ranked Proponents for each LDC;

- RFP Provision 7.5.141 provides the framework (principle) for negotiations and contracting based on the principle of "first right to negotiation and execution of a contract" being accorded to the ranked order of Proponents commencing with the highest ranked Proponent and proceeding in a consecutive order thereafter; and

- Each LDC was provided the evaluation results for their #1 and #2 ranked Proponents supported by the Attestation Letter of the Fairness Commissioner as to those rankings.

From a final contract negotiation perspective the CHEC LDCs each initiated good faith contract negotiations with their identified "best value" bidder. There were cases with some CHEC members where these negotiations stalled or failed with the "best value" bidder (Silver Spring), and the second best value bidder was invited to negotiate a procurement contract. For some CHEC members the second vendor was Elster and for others, Sensus.

Ultimately the result for CHEC member utilities was that 50% of the group was awarded Elster's Energy Axis AMI system and 50% was awarded Sensus' FlexNet™ AMI system. This evaluation process was termed as phase two in the Ontario market place and was the method by which AMI systems were selected for the vast majority of utilities in the province.

Following the selection of an AMI provider, attention was turned to the selection of an Installation Vendor and WAN provider (for those using the Elster AMI network).

Install Vendor Selection Process

CHEC's involvement in the London Hydro Phase Two Procurement Process proved to be of great value as the experience formed a foundation that ensured a sound and prudent procurement path was followed. An Installation Services RFP was created and five (5) vendors from across North America were invited to respond.

The invited vendors included Corix, Honeywell, Olameter, PowerQuest, (Keywell), and Trilliant, representing both vendors with local representation as well as vendors with extensive experience in larger markets. CHEC was confident that the most qualified and successful vendors were given the opportunity to submit proposals in response to the RFP.

CHEC's clearly stated requirement for the highest possible standards with regards to Safety were evident in every stage of the procurement process. The Request for Proposal identified CHEC's stringent Safety requirements, and included a requirement for bidder's to state their ability to either meet or exceed CHEC's guidelines. In addition to comprehensive Safety policies and procedures, CHEC's preference for a turnkey solution with the successful vendor performing all site related services and workforce management (i.e. customer communication, installation and commissioning, scheduling, dispatch and integration to back office systems, etc) was expressed.

In total, the operational considerations accounted for 40% of weighting of the evaluation with the remaining 60% attributed to the pricing received. The weighting structure was chosen to closely match that used in the 2006 CLD RFPQ process which had been found to be prudent by the regulator.

At the close of financial and technology evaluations, it was determined that Trilliant most closely matched all of CHEC's requirements; providing clear and concise Safety protocols as well as strong managerial tools to ensure all communicated policies and procedures would be properly implemented by the staff utilized within each CHEC member's service territory. These strong functional components were to be provided at a highly competitive price, which in combination resulted in the best service package being provided at the best price. Shortly after Trilliant was selected as the winning proponent, the group received notice that Olameter had acquired Trilliant and thus Olameter would be providing the services to the group.

As many utilities had a relationship with Olameter for meter reading services and Olameter was quite active in the Ontario market, this worked in the group's favour. Olameter's operational score in the RFP evaluation was strong; however their pricing was not the most favourable which attributed to their ranking as number three in the evaluation model. Given the success being enjoyed by Olameter within Ontario, there was confidence that there was minimal risk in the decision to award Olameter with the installation of CHEC's residential Smart Meters.

Util-Assist Inc. | 125 Don Hillock Drive, Unit 12 Aurora, Ontario L4G 0H8 | [t] 905.726.7771 [f] 905.726.9655 | www.util-assist.com

ODS Vendor Selection Process

CHEC member utilities recognized early on that an Operational Data Store (ODS) would be of value to support their needs for the introduction of efficiencies which would become possible through the use of the operational data available from the AMI system as the MDM/R didn't store operational data.

According to the Ministry of Energy's Functional Specification, the Advanced Metering Control Computer (AMCC – AMI network server) is limited to a maximum of 60 days for the storage of AMI data. Whereas ODS systems act as a repository to store unlimited data and have the architecture with the mechanisms in place to retain and archive data for analysis by the utility.

Many benefits can be realized through the use of an ODS system, one of which is to use the ODS to audit the mass meter installation to prevent the situation of deploying the AMI network "blind". The AMI systems traditionally will indicate that the meters are communicating but the ODS will verify the quality of the data coming from the AMI system.

Other examples of the available functionality in ODS systems include verification of all data fields being transmitted from AMI, such as:

- Readings (kWh, kW)
- Alarm Filtering (Tamper, Outage)
- Power Quality Data (Voltage)
- Perform Data Gap Analysis
- SLA management of AMI system

Due to the possibility that the provincial centralized Meter Data Management and Repository (MDM/R) would one day accommodate operational needs in addition to the billing requirements, and in keeping with the desire to minimize duplication in utility infrastructure, the utilities chose to procure a system that was an Application Service Provider (ASP) model, allowing the system to grow with the needs of each utility, and also provide flexibility with regards to contract term.

To be prepared for the deployment of residential smart meters in each utility's service territory, the ODS RFP was developed focusing on data management functionality which would definitively determine a utility's compliance with the requirements of the Ministry of Energy's Functional Specification. Additionally, the ODS system would be required to store operational data which will allow utilities to implement operational efficiencies in the immediate future.

The ODS Request for Proposal (RFP) was distributed to selected vendors in North America with fourteen (14) vendors invited to respond. These vendors included local representation as well as vendors with extensive experience in larger markets. CHEC was confident that the most qualified and successful vendors were given the opportunity to submit proposals in response to the RFP.

Util-Assist Inc. | 125 Don Hillock Drive, Unit 12 Aurora, Ontario L4G 0H8 | [t] 905.726.7771 [f] 905.726.9655 | www.util-assist.com

The evaluation team consisted of representatives from four utilities in the CHEC group with resources from Centre Wellington Hydro Ltd., Innisfil Hydro Distribution Systems Limited, Lakeland Power Distribution Ltd. and Wellington North Power Inc. volunteering to be part of the committee. This committee provided for a mixture of Elster and Sensus AMI users and a wealth of both technical and operational knowledge.

The evaluation criteria and scoring documents were prepared in advance of the release of the RFP to support a prudent process and identify scoring criteria that ensured a consistent and fair approach in the evaluation of the bids. Many of the ODS systems were considered new technology and to ensure that the written responses and functionality descriptions in the RFP matched the state of the actual technology released, vendor demonstrations were held allowing utilities the opportunity to see the actual software.

The team evaluated Bidders objectively with the end goal of selecting the best-fit service provider for an ODS solution, thereby allowing utilities to achieve their internal goals of maximizing the value from the assets in the field, while ensuring that the requirements of the provincial government are met. With financial and technology evaluations completed, it was determined that the Kinetiq ODS proposal most closely matched all of the requirements; providing strong support for the functionality requirements expressed through the RFP, as well as project management support tailored to the needs of each utility to ensure project success.

Given the experience of Kinetiq with Ontario utilities, there was confidence that there was minimal risk in the decision to award Kinetiq with the ODS component of their Smart Meter Network infrastructure. After further discussion amongst the member utilities and a review of the evaluation documents, vendors were notified of the award of the bid and Kinetiq was engaged to move forward with the contract negotiations process.

Supplied documentation reflects the analysis that went into this important decision by noting the functionality provided by the bidders as well as the pricing and associated risk of the different vendors. The decision making process regarding ODS solutions has been well documented and conclusive, to provide each utility's Executive Management team with the confidence to support the decision made by the committee. The well organized approach has ensured that the proper decisions have been made and documented with the end goal of achieving all SMI related timelines.

WAN Vendor Selection Process

CHEC members utilizing the Elster Energy Axis AMI network would be required to select a Wide Area Network (WAN) vendor to provide the communications backhaul for their AMI networks. CHEC members moved forward initiating a process for the procurement of a WAN solution in Q4 of 2008. The WAN RFP was designed with the intention of procuring a solution which would allow increased flexibility and functionality in the long term. The RFP development process included flexibility, allowing vendors to provide solutions of a wired and/or wireless nature, satisfying immediate requirements with options to expand the proposed solution, as well as ancillary services to allow savings through potential synergies. As part of the procurement process the components of service that were required were:

1. Hardware Procurement
2. Installation and Commissioning
3. Ongoing Maintenance

During every stage of the procurement process it was CHEC member's clearly stated objective that the selected WAN solution would provide a method to enable the AMI to meet the Ministry of Energy and Infrastructure's Functional Specification for the timely delivery and reliable transmission of meter data. The WAN RFP "weighting" followed a format that was found to be prudent by the regulator; in total, the operational considerations would account for 40% of the evaluation, with the remaining 60% attributed to the pricing received.

The RFP was released by CHEC on December 5, 2008 and a decision was made to select Bell/National Wireless as the provider in Q1 of 2009.

MDM/R Integration Process Project planning

Ontario Regulation 393/07: Designation of Smart Metering Entity would authorize the Independent Electricity System Operator (IESO) as the Smart Metering Entity responsible for processing all meter read interval data to provide billing quantity data to all LDCs in Ontario. This centralized system is termed as the Provincial Centralized MDM/R (MDM/R).

Having made such tremendous progress in the acquisition and implementation of systems, CHEC recognized the value in collaboration and continued to work together with Util-Assist to complete the necessary steps required to integrate their systems into the MDM/R.

As part of this strategy, Util-Assist developed and presented a series of MDM/R Education Sessions in which the CHEC members were educated about the MDM/R and the Business Process changes that would be required to effectively integrate and interact with the MDM/R on an enduring basis.

Standard processes were provided to members allowing them to tailor the processes for their own situations. Several members elected to have Util-Assist provide a more in-depth analysis of their processes and ultimately assist the LDCs in the design and development of specific processes unique to their utility.

Successfully integrating to the MDM/R would require months of education to prepare for the formalized enrolment testing run by the IESO. Dedicated resources would be required from each utility to be the test lead and engage with the IESO during the 8 week enrolment timeframe leading up to the cutover to the MDM/R (flowing all meter data). The flowing of all residential and small commercial customers'

Util-Assist Inc. | 125 Don Hillock Drive, Unit 12
Aurora, Ontario L4G 0H8 | [t] 905.726.7771
[f] 905.726.9655 | www.util-assist.com

meter data to the MDM/R would be required in order for utilities to successfully implement the new time-of-use rate structures.

On June 24, 2010, the Board issued for comment a Proposed Determination (the “June Proposed Determination”) to mandate time-of-use (“TOU”) pricing for RPP consumers by establishing the “mandatory TOU date” for each electricity distributor as contemplated in section 1.2.1 of the Standard Supply Service Code (the “SSS Code”). In the June Proposed Determination, the Board proposed that a distributor’s mandatory TOU date will be one of two dates, depending on the distributor’s progress to date against the schedule set out in its baseline plan (updated to the date of the June Proposed Determination, where applicable).

This would require the CHEC member utilities to implement time-of-use rates in their service territory based on the dates provided in the OEB determination. As of the writing of this report, approximately 30% of the CHEC member utilities have implemented time-of-use pricing in their service territories while all other members are on a path to successfully fulfill their requirements to the regulator.

Conclusion

The CHEC group members are confident that a comprehensive process has been undertaken and successfully completed, and that the due diligence requirements for all decisions related to this initiative have been satisfied.

Through the process of working together with other LDCs, CHEC has realized the true value of collaboration, having received support as well as operational and pricing efficiencies that were not possible had each LDC gone through the process on their own.

Util-Assist Inc. | 125 Don Hillock Drive, Unit 12
Aurora, Ontario L4G 0H8 | [t] 905.726.7771
[f] 905.726.9655 | www.util-assist.com

Appendix A

a) Ontario Regulation 425/06
b) Functional Specifications document

Util-Assist Inc. | 125 Don Hillock Drive, Unit 12
Aurora, Ontario L4G 0H8 | [t] 905.726.7771
[f] 905.726.9655 | www.util-assist.com

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ONTARIO REGULATION 425/06

made under the

ELECTRICITY ACT, 1998

Made: August 10, 2006
Filed: August 29, 2006
Published on e-Laws: August 31, 2006
Printed in *The Ontario Gazette*: September 16, 2006

CRITERIA AND REQUIREMENTS FOR METERS AND METERING EQUIPMENT, SYSTEMS AND TECHNOLOGY

Adoption of criteria and requirements

1. For residential and small general service consumers, the prescribed criteria and requirements for meters, metering equipment, systems and technology and any associated equipment, systems and technologies are the criteria and requirements specified in the document entitled "Functional Specification for Advanced Metering Infrastructure" dated July 14, 2006 and available at the Ministry of Energy, 4th Floor, Hearst Block, 900 Bay Street, Toronto, Ontario or at http://www.energy.gov.on.ca/english/pdf/electricity/smartmeters/Functional_Specification_for_Advanced_Metering_Infrastructure.pdf.

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FUNCTIONAL SPECIFICATION

FOR AN

ADVANCED METERING INFRASTRUCTURE

JULY 14, 2006

FUNCTIONAL SPECIFICATION

FOR AN ADVANCED METERING INFRASTRUCTURE

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FUNCTIONAL SPECIFICATION

FOR AN ADVANCED METERING INFRASTRUCTURE

1.0 APPLICATION OF SPECIFICATION

This Specification sets the required minimum level of functionality for AMI in the Province of Ontario for residential and small general service consumers where the metering of demand is not required. This Specification is not intended to apply to net metering applications.

2.0 FUNCTIONAL SPECIFICATION

2.1 Deployment

This Specification shall be met regardless of the size or scope of the AMI deployment by a distributor.

2.2 Minimum Functionality

2.2.1 As a minimum:

2.2.1.1 AMI shall collect Meter Reads on an hourly basis from all AMCDs deployed by a distributor and transmit these same Meter Reads to the AMCC and MDM/R, as required, in accordance with these Specifications; and

2.2.1.2 A Meter Read shall be collected, dated and time stamped at the end of each hour (i.e. midnight as represented by 24:00).

2.2.2 The date and time stamping of Meter Reads shall be recorded as year, month, day, hour, minute (i.e. YYYY-MM-DD hh:mm).

2.2.3 All meters shall have a meter multiplier of one (1).

2.2.4 Distributors shall provide the MDM/R with the service multiplier for transformer-type meters.

2.3 Performance Requirements

2.3.1 Collection and Transmission of Meter Reads:

2.3.1.1 AMI shall successfully collect and transmit to the AMCC and MDM/R at least 98.0% of the Meter Reads from all AMCDs deployed by a distributor in any Daily Read Period.

2.3.1.2 Meter Reads unsuccessfully collected or transmitted shall not be due to the same AMI component (including, without limitation, any AMCD) during any three (3) month consecutive time period.

2.3.1.3 AMI shall be able to collect and transmit Meter Reads during its operating life without requiring a field visit.

2.3.2 Transmission Accuracy: Over the Daily Read Period, 99.9% of the Meter Reads received by the AMCC shall contain the same information as that collected by all AMCDs deployed by the distributor.

2.3.3 AMI shall be capable of providing Meter Reads with a precision of at least 10 Watt-hours (0.01 kWh).

2.4 Technical Requirements

2.4.1 When an AMI includes AMRCs, the AMRCs shall have the ability to store meter data to accommodate the performance requirements in section 2.3.1.

2.4.2 Time Synchronization:

2.4.2.1 AMI shall be operated and synchronized to Official Time, as set by the National Research Council of Canada.

2.4.2.2 AMI shall have the capability of adjusting for changes due to local daylight savings time.

2.4.2.3 AMI installed within a distributor's service area shall have the capability of accommodating more than one (1) time zone.

2.4.2.4 Time synchronization shall be maintained in the AMI to the specified accuracy parameters set out in section 2.4.3.1 following a loss of power.

2.4.2.5 All Meter Reads shall adhere to accurate time synchronization processes to ensure an accurate accounting of electricity consumption at each meter.

2.4.3 Time Accuracy:

2.4.3.1 At all times, time accuracy in the AMI shall not exceed a ±1.5 minute variance from the time established in section 2.4.2.1.

2.4.3.2 AMI shall be able to prove that time accuracy does not exceed the permitted time variance identified in section 2.4.3.1.

2.4.4 Loss and Restoration of Power:

2.4.4.1 AMI shall detect and identify the interval in which a loss of power occurred during a Daily Read Period.

2.4.4.2 AMI shall detect and identify the interval in which power was restored following a loss of power.

2.4.5 Environmental Tolerances: All AMI components (except the AMCC) shall operate and meet the requirements in these Specifications within a temperature range of minus thirty degrees Celsius (–30° C) to positive sixty-five degrees Celsius (+65° C), and within a humidity range of zero percent (0%) to ninety-five percent (95%) non-condensing.

2.5 Advanced Metering Communication Device (AMCD)

2.5.1 Installation Within the Meter:

2.5.1.1 The AMCD shall not impair the ability of the meter to be visually read.

2.5.1.2 Meters in which an AMCD is installed shall be able to be installed in existing meter sockets or enclosures.

2.5.1.3 AMCD shall meet or exceed ANSI standards to withstand electrical surges and transients.

2.5.2 Labelling:

2.5.2.1 The AMCD shall be permanently labelled with:

(1) Legally required labelling;

(2) Manufacturer’s name;

(3) Model number;

(4) AMCD identification number;

(5) Input/output connections;

(6) Date of manufacture; and

(7) Bar code for tracking and inventory management.

2.5.3 When installed at a consumer’s location, the meter shall visibly display, as a minimum, the AMCD identification number, meter serial number and LDC badge number for the meter.

2.5.4 The AMCD shall be able to be initialized or programmed during, or prior to, field installation.

2.6 Transmission of Meter Reads

2.6.1 All Meter Reads collected during the Daily Read Period shall be received by the AMCC and transferred to the MDM/R no later than 5:00 a.m. local time following the Daily Read Period.

2.6.2 Meter Reads are not required to be transmitted in a single transmission and may be transmitted as frequently as necessary in order to meet the requirements in section 2.6.1.

2.6.3 AMCC shall transfer the information identified in section 2.6.1 using an approved protocol and file structure.

2.7 Advanced Metering Regional Collectors (AMRC)

2.7.1 LAN Communication Infrastructure:

2.7.1.1 The spectrum allocation and wattage of the radio signal used by an AMI shall not impede neighbouring frequencies.

2.7.2 When an AMI includes AMRCs:

2.7.2.1 The AMI shall provide for the continuous powering of AMRCs regardless of their location and placement.

2.7.2.2 All AMCDs shall be able to collect and transmit Meter Reads when one or more AMRC has a loss of power.

2.7.2.3 Memory and software parameters shall be maintained at all AMRC during a loss of power, whether by the provision of backup/alternate power or other solution.

2.8 Advanced Metering Control Computer (AMCC)

2.8.1 Each AMCC shall have the ability to store a rolling sixty (60) days of Meter Reads.

2.8.2 A distributor shall not aggregate Meter Reads into rate periods or calculate consumption data from the Meter Reads collected through its AMI either in its AMCC or any other component.

2.8.3 The AMCC shall be able to perform basic operational verification of Meter Reads received before transmitting these Meter Reads to the MDM/R.

2.9 Customer Account Information

2.9.1 Distributors shall provide initial information associated with customer accounts to the MDM/R on a date to be determined.

2.9.2 On an ongoing basis, distributors shall provide information associated with any change to the initial information identified in section 2.9.1 to the MDM/R at a frequency to be determined.

2.9.3 Information to be provided to the MDM//R pursuant to sections 2.9.1 and 2.9.2 is to be determined.

2.10 Monitoring & Reporting Capability

2.10.1 The AMI shall have non-critical reporting functionality and critical reporting functionality as required in this section 2.10. Information generated from this reporting functionality shall be available to the MDM/R.

2.10.2 Non-critical reporting:

2.10.2.1 At the completion of every Daily Read Period and following a transmission of Meter Reads, the AMCC shall generate a status report that includes information regarding anomalies and issues affecting the integrity of the AMI or any component of the AMI including information related to any foreseeable impact that such anomalies or issues might have on the AMI's ability to collect and transmit Meter Reads.

2.10.2.2 In addition to section 2.10.2.1, the AMCC shall generate reports:

(1) Confirming successful initialization of the AMCD's installed in the field;

(2) Confirming data linkages among an AMCD identification number, LDC badge number, serial number and customer account;

(3) Confirming that the MDM/R has successfully received notification of any changes to customer account information;

(4) Confirming that the AMCC has successfully made changes to customer account information following receipt of same from the MDM/R;

(5) Confirming the successful collection and transmission of Meter Reads or logging all unsuccessful attempts to collect and transmit Meter Reads, identifying the cause, and indicating the status of the unsuccessful attempt(s) pursuant to section 2.3.1;

(6) Confirming the accuracy of the Meter Reads received by the AMCC pursuant to section 2.3.2;

(7) Confirming that all Meter Reads have a precision of at least 10 Watt-hours (0.01 kWh) pursuant to section 2.3.3;

(8) Confirming whether the Meter Reads acquired within the Daily Read Period are in compliance with the time accuracy levels identified in section 2.4.3;

(9) Confirming whether time synchronization within the AMI or any components of the AMI has been reset within the Daily Read Period;

(10) Identifying the intervals in which a loss of power occurred and at which power was restored, following a loss of power;

(11) Addressing the functionality of the AMCD communication link, including status indicators related to the AMCD and AMRC;

(12) Identifying suspected instances of tampering, interference and theft;

(13) Flagging potential network, meter and AMCD issues; and

(14) Identifying any other instances that impact or could potentially impact the AMI's ability to collect and transmit Meter Reads to the AMCC and/or MDM/R on a daily basis.

2.10.2.3 Following a transmission of Meter Reads or at the completion of every Daily Read Period, the information in section 2.10.2.2 (5) shall be stored and used by the AMCC to assess compliance with the requirement specified in section 2.3.1.2.

2.10.2.4 The reports generated in sections 2.10.2.1 and 2.10.2.2 shall be made available to the MDM/R with a frequency to be determined.

2.10.3 Critical reporting:

Critical events are defined to include any AMI operational issue that could adversely impact the collection and transmission of Meter Reads during any Daily Read Period.

2.10.3.1 The AMI shall identify and report the following to the distributor:

(1) AMCD failures;

(2) AMRC failures;

(3) Issues related to the storage capacity of any component of the AMI;

(4) Communication links failures;

(5) Network failures; and

(6) Loss of power and restoration of power.

2.10.3.2 The reports generated in section 2.10.3.1 shall be made available to the MDM/R.

2.11 Security and Authentication:

2.11.1 The AMI shall have security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements.

2.12 Proven Technology

2.12.1 No distributor shall install more than five hundred (500) units of a particular model of electricity AMCD if a minimum of five thousand (5,000) units of the same model of electricity AMCD that is to be installed by the distributor is not currently functioning in the field as part of one or more functioning AMI.

2.13 Regulatory Requirements

2.13.1 The AMI shall meet all applicable federal, provincial and municipal laws, codes, rules, directions, guidelines, regulations and statutes (including any requirements of any applicable regulatory authority, agency, board, or department including Industry Canada, the Canadian Standards Association, the Ontario Energy Board and the Electrical Safety Authority) (collectively, "**Laws**"). For greater certainty, the AMI shall meet all applicable Laws that are necessary for the measurement of data and/or the transmission of data to and from the consumers within the Province of Ontario, including Laws applicable to metering, safety and telecommunications.

2.14 Water or Natural Gas Meter Reads

2.14.1 The AMI should be capable of supporting an increased number of Meter Reads associated with the reading and transmission of water and/or natural gas meters through additional ports on the AMCD, through optionally available multi-port AMCDs, or through additional AMCD/AMRC devices that are compatible with operating on the AMI. When procuring AMI, distributors shall obtain an indication of the capabilities of the proposed AMI to read water and natural gas meters, indicating the makes and models of such meters that can be read, and any requirements for retrofitting them.

3.0 DEFINITIONS

Within this Specification the following words and phrases have the following meanings:

"AMCC" is an advanced metering control computer that is used to retrieve or receive and temporarily store Meter Reads before or as they are being transmitted to the MDM/R. The information stored in the AMCC is available to log maintenance and transmission faults and issue reports on the overall health of the AMI to the distributor.

"AMCD" is an advanced metering communication device that is housed either under the meter's glass or outside the meter. It transmits Meter Reads from the meter directly or indirectly to the AMCC.

"AMI" means an advanced metering infrastructure. It includes the meter, AMCD, LAN, AMRC, AMCC, WAN and related hardware, software and connectivity required for a fully functioning system that complies with this Specification. With some technologies, an AMI does not include AMRCs. An AMI does not include the MDM/R.

"AMRC" is an advanced metering regional collector that collects Meter Reads over the LAN from the AMCD and transmits these Meter Reads to the AMCC.

"consumer" or "customer" means a person who uses, for the person's own consumption, electricity that the person did not generate.

"distributor" has the meaning provided in the *Ontario Energy Board Act, 1998*.

"Daily Read Period" means the 24-hour period for collecting Meter Reads, subject to the two periods annually during which changes to and from daylight savings time take place. The Daily Read Period ends at 12:00 midnight of each day.

“LAN” means a local area network, the communication network that transmits Meter Reads from the AMCD to the AMRC.

“meter multiplier” is the factor by which the register reading must be multiplied to obtain the registration in the stated units.

“Meter Read” is a number generated by a meter that reflects cumulative electricity consumption at a specific point in time.

“MDM/R” means the meter data management and meter data repository functions within which Meter Reads are processed to produce rate-ready data and are stored for future use.

“Specification” means these functional specifications.

“transformer-type meter” means a meter designed to be used with instrument transformers.

“WAN” means a wide area network, the communication network that transmits Meter Reads from the AMRC to the AMCC or, in some systems from the AMCD directly to the AMCC, and from the AMCC to the MDM/R.

Appendix B

a) Ontario Regulation 426/06

Util-Assist Inc. | 125 Don Hillock Drive, Unit 12
Aurora, Ontario L4G 0H8 | [t] 905.726.7771
[f] 905.726.9655 | www.util-assist.com

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Loi de 1998 sur la commission de l'énergie de l'Ontario

ONTARIO REGULATION 426/06

SMART METERS: COST RECOVERY

Consolidation Period: From June 25, 2008 to the e-Laws currency date.

Last amendment: O. Reg. 234/08.

This Regulation is made in English only.

Cost recovery, general

1. (1) In relation to the acquisition of smart meters, a distributor may recover its costs relating to functionality that does not exceed the minimum functionality adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the *Electricity Act, 1998,* subject to final approval by the Board and the Board's review and determination that the agreement entered into for the acquisition is economically prudent and cost effective. O. Reg. 234/08, s. 1 (1).

(1.01) In determining whether an agreement referred to in subsection (1) is economically prudent and cost effective, the Board's review shall take into consideration, but not be limited to,

(a) all costs associated with the agreement; and

(b) the costs of the agreement relative to any agreements entered into by the distributor and other distributors for comparable acquisitions. O. Reg. 234/08, s. 1 (1).

(1.1) Subject to final approval of the Board, a distributor may recover the costs it prudently incurred to comply with the enrolment requirements and technical interface requirements of the Smart Metering Entity. O. Reg. 441/07, s. 1; O. Reg. 234/08, s. 1 (2).

(2) In relation to the acquisition of smart meters, a distributor may not recover its costs relating to functionality that exceeds the minimum functionality adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the *Electricity Act, 1998* unless the costs are approved by the Board. O. Reg. 426/06, s. 1 (2); O. Reg. 234/08, s. 1 (3).

(3) In reaching a decision under subsection (2), the Board may consider the matters that it considers appropriate, including evidence that the functionality that exceeds the minimum functionality adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the *Electricity Act, 1998* benefits the distributor's consumers. O. Reg. 426/06, s. 1 (3).

(4) In this section,

"smart meters" includes smart meters, metering equipment, systems and technology and any associated equipment, systems and technologies. O. Reg. 234/08, s. 1 (4).

Cost recovery, meter data functions

2. (1) No distributor shall recover any costs associated with meter data functions to be performed by the Smart Metering Entity. O. Reg. 426/06, s. 2 (1).

(2) Despite subsection (1), distributors may recover costs associated with functions related to meter data that are contemplated to be performed by distributors by the criteria and requirements adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the *Electricity Act, 1998*. O. Reg. 426/06, s. 2 (2).

(3) Subsection (1) does not prevent distributors from recovering costs that are approved by the Board pursuant to section 1 that are associated with functions related to meter data that relate to a distributor's operation of its distribution system, but only if those functions are not meter data functions to be performed by the Smart Metering Entity. O. Reg. 426/06, s. 2 (3).

(4) Subsection (1) does not apply to distributors with service areas identified as priority installations in Ontario Regulation 428/06 (Priority Installations) made under the *Electricity Act, 1998*. O. Reg. 426/06, s. 2 (4).

(4.1) Subsection (1) does not prevent a distributor from recovering costs, if approved by the Board, that the distributor incurred as a result of supporting the IESO with finalizing the design of the requirements and processes for the interface and integration of the Smart Metering Entity's system with the distributor's billing and metering systems. O. Reg. 392/07, s. 1.

(4.2) The distributor's cost recovery under subsection (4.1) is subject to the Board receiving confirmation from the IESO that the distributor supported the IESO as described in subsection (4.1) and that the distributor was one of the first five distributors whose billing and metering systems were integrated with the Smart Metering Entity's system. O. Reg. 392/07, s. 1.

(5) In this section,

"meter data functions" means those functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to Ontario Regulation 393/07 (Smart Metering Entity) made under the *Electricity Act, 1998*. O. Reg. 426/06, s. 2 (5); O. Reg. 234/08, s. 2.

Cost recovery, replaced meter assets

3. (1) Subject to Board order, to ensure that distributors are not financially disadvantaged by the implementation of the smart metering initiative, distributors may recover the costs associated with meters owned before, on or after January 1, 2006 being replaced because of the smart metering initiative if,

(a) the meter being replaced was not acquired in contravention of section 53.18 of the *Electricity Act, 1998*; and

(b) the meter is replaced with a smart meter authorized for installation under the *Electricity Act, 1998*. O. Reg. 441/07, s. 2.

(2) The Board shall determine the period of time over which the costs referred to in subsection (1) may be recovered, in order to protect the interests of consumers with respect

to prices. O. Reg. 441/07, s. 2.

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Appendix C

a) Ontario Regulation 427/06
b) Ontario Regulation 235/08

Util-Assist Inc. | 125 Don Hillock Drive, Unit 12
Aurora, Ontario L4G 0H8 | [t] 905.726.7771
[f] 905.726.9655 | www.util-assist.com

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Electricity Act, 1998
Loi de 1998 sur l'électricité

ONTARIO REGULATION 427/06

SMART METERS: DISCRETIONARY METERING ACTIVITY AND PROCUREMENT PRINCIPLES

Consolidation Period: From June 25, 2008 to the e-Laws currency date.

Last amendment: O. Reg. 235/08.

This Regulation is made in English only.

Definition

0.1 In this Regulation,

"smart meters" includes smart meters, metering equipment, systems and technology and any associated equipment, systems and technologies. O. Reg. 235/08, s. 1.

Authorized discretionary metering activity

1. (1) The following activities are authorized discretionary metering activities for the purposes of section 53.18 of the Act:

1. Metering activities conducted pursuant to the distributor's Conservation and Demand Management Plan approved by a Board order referenced as RP - 2004 - 0203, including pursuant to a reallocation of funds within an approved Conservation and Demand Management Plan as authorized by the Board order approving the Conservation and Demand Management Plan or that is otherwise approved by the Board.
2. If not otherwise authorized by this subsection, a distributor may utilize funds to conduct metering activities that are for the purpose of testing smart meter technology if,
   i. the distributor has the prior approval of the Board, and
   ii. the funds that are utilized were collected pursuant to the Board's approval to include capital and operating costs related to smart meters in distributors' revenue requirements for 2006, as set out in the Board's Generic Issues decision, dated March 21, 2006 and referenced as RP - 2005 - 0020, as is incorporated into each distributor's 2006 electricity distribution rate order provided by the Board pursuant to section 78 of the *Ontario Energy Board Act, 1998*.
3. Metering activities conducted by Enersource Corporation, Powerstream Inc., Hydro Ottawa Limited, Horizon Utilities Corporation, Toronto Hydro-Electric System

Limited and Veridian Connections Inc. pursuant to the process initiated in the Request for Pre-Qualification for Advanced Metering Infrastructure Procurement and Installation issued by Enersource Corporation on behalf of itself and the other referenced utilities and dated May 2, 2006.

3.1 Metering activities conducted by a distributor listed in paragraph 3, if the smart meters were procured subsequent to the process referred to in paragraph 3.

4. Metering activities conducted by a distributor that has had its smart meters procured on its behalf by one or more of Enersource Corporation, Powerstream Inc., Hydro Ottawa Limited, Horizon Utilities Corporation, Toronto Hydro-Electric System Limited or Veridian Connections Inc. pursuant to the process referred to in paragraph 3.

5. Metering activities conducted pursuant to the Request for Proposal for Smart Metering Services issued by Hydro One Networks Inc. and dated March 4, 2005.

6. Metering activities conducted by a distributor that has had its smart meters procured on its behalf by Hydro One Networks Inc. pursuant to the process referred to in paragraph 5.

7. Metering activities conducted by distributors if the activities meet the following criteria:

   i. the activities are for service areas identified as priority installations by Ontario Regulation 428/06 (Priority Installations) made under the Act, and

   ii. smart meter deployment plans have been filed with the Minister by the distributor.

8. Metering activities conducted by a distributor that has procured its smart meters pursuant to and in compliance with the parameters and process established by the Request for Proposal for Advanced Metering Infrastructure (AMI) – Phase 1 Smartmeter Deployment dated August 14, 2007, together with any amendments to it, issued by London Hydro Inc. O. Reg. 427/06, s. 1 (1); O. Reg. 153/07, s. 1 (1); O. Reg. 235/08, s. 2 (1-4).

(2) The smart meters used in relation to activities authorized as discretionary metering activities in subsection (1) shall comply with the criteria and requirements adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the Act. O. Reg. 427/06, s. 1 (2); O. Reg. 153/07, s. 1 (2); O. Reg. 235/08, s. 2 (5).

(2.1) Despite subsection (2), the smart meters used in relation to activities authorized as discretionary metering activities in paragraph 1 of subsection (1) that were conducted before the day this subsection comes into force are not required to comply with the criteria and requirements adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the Act. O. Reg. 153/07, s. 1 (3); O. Reg. 235/08, s. 2 (6).

(3) Any procurement associated with the activities authorized as discretionary metering activities under subsection (1), other than activities referenced in paragraphs 1 and 2 of subsection (1), shall comply with the procurement requirements set out in section 2. O. Reg. 427/06, s. 1 (3); O. Reg. 153/07, s. 1 (4).

(4) The activities authorized as discretionary metering activities in subsection (1) are subject to the cost recovery requirements set out in Ontario Regulation 426/06 (Smart

Meters: Cost Recovery) made under the *Ontario Energy Board Act, 1998*. O. Reg. 427/06, s. 1 (4).

Procurement

2. (1) When a distributor enters into a procurement process in relation to the smart metering initiative, the distributor shall ensure,

(a) that the procurement process complies with the principles set out in subsection (2); and

(b) that any agreement entered into as a result of the procurement is economically prudent and cost effective, taking into consideration, but not limited to,

(i) all costs associated with the agreement, and

(ii) the costs of the agreement relative to any prior agreement entered into by the distributor for comparable acquisitions. O. Reg. 427/06, s. 2 (1); O. Reg. 235/08, s. 3 (1).

(2) Distributors shall ensure that a procurement process in relation to the smart metering initiative complies with the following principles:

1. The procurement process, including the procedures used in the process and the selection criteria, must be fair, open and accessible to a range of interested bidders.

2. The procurement process must be competitive.

3. Conflicts of interest, both actual and potential, of bidders must be disclosed in the bidders' proposals and the process must ensure that,

i. the selected bidder will not have a conflict of interest in respect of the deliverables under the agreement entered into as a result of the procurement, or

ii. the selected bidder will be required to comply with requirements established by the distributor to address an actual or potential conflict of interest.

4. There must be no unfair advantage in the procurement process. O. Reg. 427/06, s. 2 (2).

(3) A distributor may only procure or utilize smart meters from an affiliate, if the affiliate is the selected bidder in a procurement process that satisfies the requirements of this section. O. Reg. 427/06, s. 2 (3); O. Reg. 235/08, s. 3 (2).

(4) The Minister or the Board may on notice require that a distributor provide to the Minister or the Board, as the case may be,

(a) information relating to the procurement or installation of smart meters including information concerning pricing, contractual arrangements, and status of installations; and

(b) information relating to a procurement, which information was obtained or developed during the procurement, including information concerning the selection of the successful bidder. O. Reg. 153/07, s. 2; O. Reg. 235/08, s. 3 (3).

(5) The notice in subsection (4),

(a) shall be in writing;

(b) shall set out a time frame in which the distributor must reply; and

(c) shall specify the information that the distributor must supply. O. Reg. 427/06, s. 2 (5).

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ONTARIO REGULATION 235/08

made under the

ELECTRICITY ACT, 1998

Made: June 17, 2008
Filed: June 25, 2008
Published on e-Laws: June 26, 2008
Printed in *The Ontario Gazette*: July 12, 2008

Amending O. Reg. 427/06

(Smart Meters: Discretionary Metering Activity and Procurement Principles)

Note: Ontario Regulation 427/06 has previously been amended. Those amendments are listed in the Table of Current Consolidated Regulations – Legislative History Overview which can be found at www.e-Laws.gov.on.ca.

1. Ontario Regulation 427/06 is amended by adding the following section:

Definition

0.1 In this Regulation,

"smart meters" includes smart meters, metering equipment, systems and technology and any associated equipment, systems and technologies.

2. (1) Subsection 1 (1) of the Regulation is amended by adding the following paragraph:

3.1 Metering activities conducted by a distributor listed in paragraph 3, if the smart meters were procured subsequent to the process referred to in paragraph 3.

(2) Paragraph 4 of subsection 1 (1) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

(3) Paragraph 6 of subsection 1 (1) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

(4) Subsection 1 (1) of the Regulation is amended by adding the following paragraph:

8. Metering activities conducted by a distributor that has procured its smart meters pursuant to and in compliance with the parameters and process established by the Request for Proposal for Advanced Metering Infrastructure (AMI) – Phase 1 Smartmeter Deployment dated August 14, 2007, together with any amendments to it, issued by London Hydro Inc.

(5) Subsection 1 (2) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

(6) Subsection 1 (2.1) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

3. (1) Clause 2 (1) (b) of the Regulation is revoked and the following substituted:

(b) that any agreement entered into as a result of the procurement is economically prudent and cost effective, taking into consideration, but not limited to,

(i) all costs associated with the agreement, and

(ii) the costs of the agreement relative to any prior agreement entered into by the distributor for comparable acquisitions.

(2) Subsection 2 (3) of the Regulation is amended by striking out "metering equipment, systems and technology and any associated equipment, systems and technologies".

(3) Clause 2 (4) (a) of the Regulation is amended by striking out "metering equipment, systems and technology and any associated equipment, systems and technologies".

4. This Regulation comes into force on the day it is filed.

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Appendix D

a) Ontario Regulation 393/07

Util-Assist Inc. | 125 Don Hillock Drive, Unit 12
Aurora, Ontario L4G 0H8 | [t] 905.726.7771
[f] 905.726.9655 | www.util-assist.com

Ontario

ServiceOntario
e-Laws

ONTARIO REGULATION 393/07

made under the

ELECTRICITY ACT, 1998

Made: March 28, 2007
Filed: July 26, 2007
Published on e-Laws: July 27, 2007
Printed in *The Ontario Gazette*: August 11, 2007

DESIGNATION OF SMART METERING ENTITY

Designation of IESO

1. The IESO is designated as the Smart Metering Entity.

Non-application of *Business Corporations Act*

2. Other than as prescribed in Ontario Regulation 610/98 (The IMO) made under the Act, the *Business Corporations Act* does not apply to the IESO.

Exemption, s. 53.10 of Act

3. The IESO is exempt from section 53.10 of the Act.

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PRP International, Inc.

Fairness Advisory Services

October 9, 2009

Innisfil Hydro Distribution Systems Ltd.
2073 Commerce Park Drive
Innisfil, ON L9S 4A2

Attention: George Shaparew, President

Dear Mr. Shaparew:

Subject: Attestation Letter (Negotiations) of the Fairness Commissioner
Innisfil Hydro Distribution Systems Ltd. – KTI/Sensus Limited
Contract Award
Advanced Metering Infrastructure RFP, August 2007
London Hydro & Consortium of LDCs Smartmetering Project

PRP International, Inc. is pleased to submit its Attestation Letter (Negotiations) of the Fairness Commissioner for the noted negotiations and contracting phase of the London Hydro AMI Request for Proposal (RFP) procurement. This judgment is being provided for the information and use of Innisfil Hydro Distribution Systems Ltd., in its administration of the contract awarded to its #3 ranked Proponent, KTI/Sensus Limited following unsuccessful negotiations with its #1 ranked Proponent, Silver Spring Networks and its #2 ranked Proponent, Elster Metering.

"It is the judgment of PRP International, Inc.(as the Fairness Commissioner engaged by Innisfil Hydro Distribution Systems Ltd. *for the phase of negotiations and contract award) that the successful conclusion of negotiations and contract award to* KTI/Sensus Limited, *was undertaken in accordance with the principles for such negotiations and contract award set out in the RFP, issued August 14, 2007 and the Fairness Protocol, issued August 2008."*

A backgrounder and summary of the Fairness Protocol is attached and forms part of this Attestation Letter (Negotiations).

Yours truly,

Peter Sorensen
President

Attachment: Negotiations and Contract Phase Backgrounder

203 - 8 Queen Street, Summerside, PEI C1N 0A6
Direct telephone: 902.436.3930 Fax: 604-677-5409
Email: fairness@telus.net

BACKGROUNDER TO FAIRNESS CONFIRMATION / ATTESTATION
Advanced Metering Infrastructure Procurement

TO WHOM IT MAY CONCERN:

Background:

- A Request for Proposal procurement transaction was conducted by London Hydro Inc., as the lead sponsoring Local Distribution Company (LDC) and with a consortia of another 63 LDCs, during the period August 2007 to July, 2008;
- The evaluation and selection phase of the RFP provided for the determination of the #1 and #2 ranked Proponents for each LDC;
- RFP Provision 7.5.14[1] provides the framework (principle) for negotiations and contracting based on the principle of "first right to negotiation and execution of a contract" being accorded to the ranked order of Proponents commencing with the highest ranked Proponent and proceeding in a consecutive order thereafter; and
- Each LDC was provided the evaluation results for their #1 and #2 ranked Proponents supported by the Attestation Letter of the Fairness Commissioner as to those rankings.

Fairness Coverage Objective:

Normally, fairness coverage terminates with the determination of the ranked Proponents following the evaluation and selection phase of the RFP; however, certain LDCs expressed a wish to secure additional fairness coverage during the subsequent phase of negotiations and contract award. The objective for this second phase fairness coverage is to assure that LDCs undertook a phase of negotiations and contracting that meets the RFP provisions of consecutive negotiations where required, e.g. with their top two ranked Proponents and in the event of unsuccessful negotiations with the #1 ranked Proponent, a subsequent contract award to the next ranked Proponent would be on an equitable basis as was the requirements in the negotiations with the #1 ranked Proponent.

---

1 7.5.14 **Final Contract Negotiations**

Any conditions and provisions that a bidder seeks shall be a part of this proposal. Notwithstanding, nothing herein shall be interpreted to prohibit London Hydro from introducing or modifying contract terms and conditions during negotiation of the final contract.

London Hydro has scheduled no more than two weeks for contract negotiations (if necessary), and expects the successful bidder to maintain a prompt and responsive negotiation to accomplish and complete final contract agreement within that time period. If contract negotiations exceed an interval acceptable to London Hydro, London Hydro retains the option to terminate negotiations and continue to the next apparent successful bidder, at the sole discretion of London Hydro. Said interval shall in no event be less than three weeks.

Fairness Protocols:

- A Fairness Protocol was developed and issued to all LDCs, in August 2008 that set forth the best practices for fair consecutive-based negotiations and contract award.
    - The fundamental principle of the Protocol was the requirement for the LDC to establish the negotiations agenda for their top ranked Proponents and submit a copy to the Fairness Commissioner prior to engagement of their #1 ranked Proponent, i.e. the agenda would demonstrate a common statement of work, a LDC standard for pass/fail in their negotiations and the negotiation issues would only differ to the extent of the respective Proponent's technical solution being offered.

Form of Fairness Confirmation / Attestation[2]:

1. A confirmation of fair negotiations and contract award would be issued if the LDC's #1 ranked Proponent was awarded a contract; the original Attestation Letter remains in effect.

2. An Attestation of fair negotiations and contract award would be issued if the LDC determined that their #1 Proponent was to be set aside and the LDC successfully contracted with their next ranked Proponent, e.g. their #2; the original Attestation Letter is thus superseded by the Negotiations and Contract Award Attestation Letter.

Local Distribution Company:

Innisfil Hydro Distribution Systems Ltd.

Mr. George Shaparew
President
Innisfil Hydro Distribution Systems Ltd.
2073 Commerce Park Drive
Innisfil, ON L9S 4A2

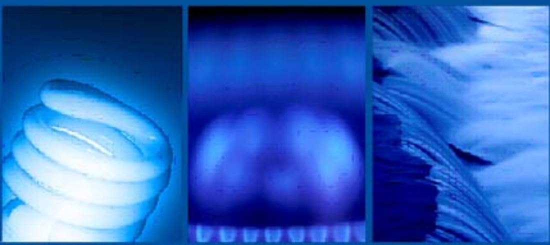
---

[2] **Conditions on the rendering of this Confirmation / Attestation.**

- The three Negotiations Agenda were provided by IHDS, via its agent Util-Assist;
- Fairness Commissioner undertook no direct participation or oversight in the negotiations between IHDS and their ranked Proponents;
- The successful contract award was based on the IHDS criteria and no independent analysis nor any comparison with the evaluation results of the RFP process was carried out by the Fairness Commissioner; and
- The confirmation of the Fairness Commissioner was based on the progress report(s) provided by IHDS, via its agent Util-Assist.

util-assist

utility strategic operational assistance



CornerstonE
Hydro Electric Concepts

Request for Proposal

Smart Meter Installation Services
RFP#: 2008-1024

October 24, 2008

Section 1: Introduction

1.1 Background

Cornerstone Hydro Electric Concepts (CHEC) members have been working collaboratively through the planning and preparation stages for the Smart Meter Initiative. The CHEC Group is an association of electricity distribution utilities modeled after a cooperative to share resources and proficiencies as the Ontario electricity industry continues its transformation.

The mission of the CHEC Group is to be recognized as the premier LDC Cooperative in the province, by meeting or exceeding member expectations through the sharing of services, opportunities, knowledge and resources. The values of the CHEC Group include the sharing of resources, both intellectual and technical, enabling members to deliver value to their customers and shareholders ensuring competitiveness in the marketplace. Together the mission and value statements represent lofty but attainable goals for the CHEC Group.

Collaboratively the CHEC group represents more than 110,000 residential end points in Ontario and is comprised of the following member utilities:

Centre Wellington Hydro Ltd.
COLLUS Power Corp.
Grand Valley Energy Inc.
Innisfil Hydro Distribution Systems Ltd.
Lakefront Utilities Inc.
Lakeland Power Distribution Ltd.
Midland Power Utility Corporation

Orangeville Hydro Limited
Orillia Power Distribution Corporation
Parry Sound Power Corporation
Rideau St. Lawrence Distribution Ltd.
Wasaga Distribution Inc.
Wellington North Power Inc.
Westario Power Inc.

CHEC members wish to procure Installation Services from a qualified Bidder at a firm, fixed price; this documentation sets out the procedural and technical requirements of CHEC for its Advanced Metering Infrastructure (AMI) System Installation service requirements.

1.1.1 Provincial Mandate

As part of its energy conservation effort, the Ontario government has made a commitment to replace all existing meters (5 million) with smart meters by 2010. Phase One utilities have fulfilled their commitments to install 1 million smart meters by Dec 31, 2007 which assisted the government in exceeding their interim goal of 800,000 by Dec 31, 2007. Focus now shifts to the Phase Two implementation of a Smart Meter Network.

The underlying premise behind the provincial mandate to install these meters is to educate customers on their consumption habits and implement new rate structures that will encourage load shifting, and the conservation of energy.

1.1.2 The CHEC Approach to Smart Metering

With respect to the Provincial government's Smart Metering Initiative, CHEC has taken a collaborative approach to becoming educated on this mandate by working with other Ontario utilities and advocacy groups. CHEC hopes to evaluate Bidders as objectively as possible with the end goal of selecting the best-fit service provider for implementation services, thereby allowing CHEC to achieve their goals, as well as those of the provincial smart meter mandate.

Along with satisfying the provincial mandate of measuring "how much electricity a customer uses each hour of the day, and to use that data to charge customers an energy price that varies depending on when the electricity was consumed" (OEB Smart Meter Plan; January 26, 2005; page i); CHEC will also implement the Smart Meter Network to improve overall efficiency within the associated service territories.

Real time connectivity with the end use consumer through the installed networks will allow for improvements in the maintenance and management of the distribution network (i.e. improved outage management and restoration) and the utilization of existing infrastructure (e.g. Fibre) where available, will allow for cost effective implementation of these systems.

1.1.3 AMI Terminology

For the purposes of this procurement process, CHEC have opted to utilize the terminology as defined by the Ministry of Energy in their *Functional Specification for an Advanced Metering Infrastructure Version 2* (dated July 5, 2007), Section 3, *Definitions.* For reference, this document has been included herein as Appendix "A". Any additional terms that have been utilized in this document, which have not been defined in the aforementioned document, which may require clarification, have been defined in Section 1.1.4 *Other Terms*.

1.1.4 Other Terms

1. ***Route Acceptance*** shall refer to the process by which CHEC accepts an existing meter reading route as having been 100% saturated with the AMI being installed through this RFP. Route Acceptance is the process which definitively determines whether the responsibilities of the Installation Vendor (being procured through this document) have been achieved.
2. ***Bidder*** shall refer to the vendor proposing a solution to this RFP document by submission of a Proposal.
3. ***Costs** and **Price***. Within this document, the terms "Costs" and "Price" are used interchangeably, and should be interpreted as including conversion costs, life-cycle costs, etc. Bidder should be sure to provide details regarding the amount charged for the given commodity or service.
4. ***Proposal*** shall mean the Bidder's written response provided to CHEC in accordance with this RFP. The Proposal shall include all written material submitted by Bidder as of the date set forth in the Key Dates (Section 2.1 *Key Dates*).
5. ***Unsafe Meter*** shall mean meters, meter bases, or other infrastructure which creates an electrically unsafe situation for the meter installer or for the general public. This can include situations where access to the meter for the purpose of meter exchange poses a safety risk (i.e. confined spaces). The manner in which Unsafe Meters are to be dealt with has been detailed in Section 3.2.2 *Unsafe Meter Bases*.
6. ***Refused Access*** shall refer to situations where the customer is present at the location where a meter exchange is required, but refuses access to the meter. It is expected that the Installer would accommodate unique situations such as Refused Access through the policies and procedures which CHEC have requested in Section 7: *Customer Communications*.
7. ***Non Installable Account*** is the "Comment Code" or "Note" that will be used by the Bidder to indicate that a meter installer has visited a premise (3) times and utilized telephone scheduling attempts two (2) times, and has not been successful at installing a meter. In this case the meter exchange service order can be returned to CHEC for resolution with no associated implications for not meeting installation targets.
8. ***Installer*** shall refer to the successful Bidder. The term Installer will be used when stating future requirements, to be performed only by the successful Bidder.

9. ***Field Service Representative*** or ***Field Service Personnel*** shall refer to the employees of the Installer which are actually performing the work, and which are monitored by the Installer to ensure proper protocols are followed.
10. ***Contractor*** shall refer to the Electrical Contractor retained by CHEC for upgrading infrastructure, and performing any other services beyond the scope of this document.

1.2 Description of Environment

Please refer to CHEC_InstallationRFP_PricingSheet_Oct2008.xls for details regarding customer count, meter count, etc.

Section 2: Instructions to Bidders

This Request for Proposals (RFP), establishes the system products and services that CHEC wishes to acquire. This bid document is the basis upon which CHEC seeks firm proposals from selected Bidders and upon which proposals will be evaluated. The documents are:

- This RFP (a pdf document), including Appendices that are integral to it.
- CHEC_InstallationRFP_PricingSheet_Oct2008.xls, a Microsoft Excel workbook. This file contains scoring criteria, the compliancy signoff sheet that is to be printed and included with the response, and tabs that allow for entry of pricing information. This workbook will heretofore be referred to as the Pricing and Compliancy spreadsheet.

2.1 Key Dates

Below is the expected timeline that CHEC will be following during the evaluation of submitted proposals. As can be seen, it is the intention of CHEC to make its decision by December 19, 2008. This time line will allow for contract negotiation and signing, so that installation can begin according to the anticipated start date of February 2, 2009.

Installation Services RFP released by CHEC :	**October 24, 2008**
Intention to bid:	**October 31, 2008**
Final Questions Due:	**November 7, 2008**
Answers to Questions:	**November 14, 2008**
Closing Time (Proposals Due):	**3:00 pm; November 21, 2008**
Proposal Decision:	**December 19, 2008**
Anticipated Start Date:	**February 2, 2009**
Required Project Completion Date:	**April 30, 2010**

2.2 Intention to Bid

Recipients of this RFP are asked to inform CHEC of their intention to bid, by completing the template form found in Section 2.15 *Proposal Forms*, and by submitting this form by the date shown in Section 2.1 *Key Dates*. Recipients that express intention to bid will be included in all correspondence (if any) during the bidding process. Please provide full contact information and expression of intention via the provided form to the CHEC contact named in Section 2.4 *Submission of Bids*.

2.3 Components of Service

It is the intent of CHEC to procure a turn-key solution. Strategic alliances may be formed to provide a turn-key solution, or Bidders may be interested in performing only certain components of the project. Bidders are asked to clearly indicate which components of the Project are being bid.

CHEC reserves the right to award some, none, or all of the components through this process to one or many Bidders.

2.4 Submission of Bids

Proposals submitted in response to this RFP will be submitted by 3:00 PM Eastern Time on November 21, 2008 (the due date, as per Section 2.1 *Key Dates*) to:

Attn: Ms. Ruth Tyrell
CHEC Group
c/o Orangeville Hydro
400 C Line
Orangeville, ON L9W 2Z7

Bidders are requested to submit bids that are complete and unambiguous without the need for additional explanation or information. CHEC reserves the right to make a final determination as to whether a bid is acceptable or unacceptable solely on the basis of the bid as submitted, and proceed with bid evaluation without requesting further information from any Bidder. If CHEC deems it desirable and in its best interest, CHEC may, in its sole discretion, request from any Bidder or Bidders additional information clarifying or supplementing any submitted bid.

Proposals received after the due date will remain unopened and will not be considered for selection. CHEC does not currently plan to grant extensions of the proposal due date, but reserves the right to do so. In the unlikely case that an extension is granted, notice of such extension will be provided to all Bidders at least one week prior to due date. Proposals will be submitted in hard copy to the street address above. All Proposals will remain the property of CHEC members.

2.4.1 Submission Requirements

1) A complete Proposal will consist of one (1) original and thirteen (13) copies complete with all supporting data, and one (1) electronic soft copy complete with all supporting data.
2) Accompanying the Bidder's response document should be the Proposal Form provided in Section 2.15 *Proposal Forms*.
3) The required format of the Bidder's response document is outlined in Section 2.4.3 *Proposal Format Instructions*.
4) The Pricing and Compliancy spreadsheet will allow for the Bidder to enter their pricing information in a standard format, as well as allow the Bidders to attest to their company's compliancy with the appropriate Health and Safety Requirements. Failure to properly complete this document is grounds for disqualification, as highlighted in Section 2.4.4 *Grounds for Disqualification*.
5) The original hard copy shall be clearly identified as "ORIGINAL"; the remainder (i.e. thirteen copies) shall be marked as "COPY". In the event of discrepancy between the copies of the Proposal Submission, the one marked "ORIGINAL" shall prevail. Each Bidder's submission shall consist of the required documents with the required number of copies of all commercial information, including pricing, terms and conditions and exceptions (if applicable). Faxed or late Proposals will not be accepted. Proposals must be sealed and marked clearly quoting the Proposal Number referred to on the cover sheet of the Proposal Documents. The use of any means of delivery of a Proposal shall be at the risk of the Bidder.
6) Any Bidder wishing to provide additional information other than what is requested in the RFP Document must place such additional information in a separate envelope marked Additional Information attached to the outside of the Proposal envelope. Any Additional Information or any unsolicited value-added alternatives may, in CHEC's absolute discretion, be given due consideration, or not.
7) CHEC shall not be liable for, nor shall it reimburse any Bidder for costs incurred in the preparation of Proposals, or any other services or samples that may be requested as part of the evaluation process.
8) The Proposal Forms shall be signed under the Corporate Seal of the Bidder, by the duly authorized signing officer(s). All submitted pages shall be initialled by such officer(s).

2.4.2 Pricing and Compliancy Spreadsheet

A Microsoft Excel workbook has been provided with this pdf document (entitled CHEC_InstallationRFP_PricingSheet_Oct2008.xls). The following tabs are included within this Pricing Spreadsheet:

i) CHEC_BidderCompliancy: This tab requires completion by the Bidder, and will act as their compliancy statement according to the requirements of Section 2.4.4 *Grounds for Disqualification*.

ii) Pricing_Option1: Option 1 tabs require completion by the Bidder, and represents the pricing for the Bidder to provide installation services as outlined within this RFP. Within the spreadsheet there are 14 tabs provided for Option 1, allowing the bidder to provide pricing according to Option 1 requirements (i.e. services as outlined within the RFP) for each utility individually, as well as for the utilities acting collaboratively. It is hoped that there will be incentive to continue moving forward through this initiative in a collaborative manner.

iii) Pricing_Option2: This tab is optional and allows the Bidder to provide pricing in an alternative format, should they desire to do so, and are of the opinion that their services are better represented with pricing apart from that outlined on the Pricing_Option1 tab. Bidders are free to add additional pricing tabs as required should they feel that there are more than one alternative option which may allow for more competitive pricing (i.e. according to a more or less aggressive timeline, holding off project commencement until a different time of year (i.e. spring vs, winter, etc.)).

Note: Pricing_Option1 is mandatory, Pricing_Option2 is optional.

iv) Eval_Criteria: this tab is for reference, it is a copy of the table that is shown in Section 2.9 *Proposal Evaluation*.

v) WFM_Functionality: This tab requires completion by the Bidder, and will demonstrate the functionality inherent to the WFM system being utilized to provide installation services.

2.4.3 Proposal Format Instructions

Each Bidder's response will be organized as per the following:

a) Section 1 of the proposal will contain the Bidder’s Executive Summary, no more than two pages in length that introduces the Bidder and highlights key features of the proposal.
b) Section 2 of the proposal will contain the statement of compliance that is included within the Pricing and Compliancy Spreadsheet, and which is described in Section 2.4.2 *Pricing and Compliancy Spreadsheet*, subsection i).
c) Section 3 of the Bidder’s proposal will contain the requirements of Section 3 of this RFP Document (Section 3: *Health and Safety*), in the order presented in this document, with the numbering used in this document.
d) Section 4 of the Bidder’s proposal will contain a statement of recognition that the Bidder understands CHEC’s schedule for deployment and the deployment territories, and that they are providing a bid response with the intention of performing the required services for CHEC. Given the diverse nature of the service territories, and that there are Smart Meter deployments occurring across the province, Bidders have the opportunity within this section to demonstrate, through submitted documentation/statements, how they will be able to accommodate the unique requirements of CHEC (i.e. staffing across the area, for the timelines projected).
e) Section 5 of the Bidder’s proposal will contain the requirements of Section 5 of this RFP Document (Section 5: *Bidder Information*), in the order presented in this document, with the

numbering used in this document.

f) Section 6 of the Bidder's proposal will contain the requirements of Section 6 of this RFP Document (Section 6: *Installation Services*), in the order presented in this document, with the numbering used in this document.

g) Section 7 of the Bidder's proposal will contain the requirements of Section 7 of this RFP Document (Section 7: *Customer Communications*), in the order presented in this document, with the numbering used in this document.

h) Section 8 of the Proposal **should be provided in a separate envelope which has been clearly marked "PRICE OFFER".** This section will contain the summary pages pertaining to the Price Offer, contained within the Pricing and Compliancy Spreadsheet. The Bidder's detailed itemized pricing information for all goods or services is to be contained within the Pricing and Compliancy Spreadsheet which is to be included with the response in its entirety as well as within this section. Any alternative pricing offers may also be included within the Pricing and Compliancy Spreadsheet (tab Pricing_Option2 is included for this purpose, as described in Section 2.4.2 *Pricing and Compliancy Spreadsheet*). All pricing shall be expressed in Canadian currency, exclusive of taxes.

2.4.3.1 Sample Responses to Demonstrate Format

Within the section or subsection heading an indicator has been included to specify whether the Bidder should provide information pertaining to the functionality of their product/service (with regards to the section requirements), or a statement of compliancy AND information pertaining to the functionality of their product with respect to the requirement of the section. Where no indicator is included, a response is not required.

(I) When an (I) has been included with the section heading, CHEC requires Information regarding the proposed system's functionality, and the methodology utilized to satisfy the RFP requirement.

(C) When a (C) has been included with the section heading, CHEC requires a statement of compliancy from the Bidder. Within the proposal documentation, the Bidder is required to state the compliancy with the requirement by stating Fully Compliant, Partially Complaint, or Not Compliant.

(CI) When a (CI) has been included with the section heading, CHEC requires both a statement of compliancy, and Information regarding the proposed functionality, and the methodology utilized to satisfy the RFP requirement.

The method with which the Bidder provides information and compliancy statements is detailed within the individual sections, as well as within the Pricing and Compliancy Spreadsheet.

In Section 2.4.3 Proposal Format Instructions, subsections c) through g) it has been specified that the order and numbering used within this document be utilized. A sample has been provided here.

5.2 Company Size and Location (I)

What is the current size (number of employees), turnover rates for last three (3) years, and location(s) of the Bidder's company?

Bidder's Functionality Statement: Bidder X currently employs 600 employees. 500 of these employees are Field Service Representatives. Of the 100 remaining office and management staff, 37 are within the Operations division providing ample redundancy and support to effectively manage this project. Bidder X's head office is located in Alabama, with satellite offices in Toronto, London, and

Ottawa. This project will be managed from the Toronto office. Turnover, while generally higher in the field service industry, is considered low at 3%. We attribute this to an effective Safety and Training program (1 week) in which employees receive ample safety training as well as introduction to the company incentive program which has been seen to improve morale amongst field service employees.

SAMPLES of response for Section 6: *Installation Services*, demonstrating that the section numbering from this document is to be retained, and that each section should be included, and where required shall include a statement of compliance.

6.1.1 Minimum Competencies (C)

Before installing meters the Installer shall ensure the Field Service Personnel are customer service oriented, have flexible work hours and are bonded, and the Installer shall maintain a process to ensure these requirements are met.

The Installer shall operate within specific procedures and operating conditions in adherence with procedures and training that CHEC will provide. Upon conclusion of the CHEC training, it will be the Installer's responsibility to ensure that new employees receive the same level of training as those employees which receive the training through CHEC.

Bidder's declaration of compliance: **Fully Compliant**

6.5.6 GPS (CI)

In addition to installing the meter, capturing the LAN ID and Meter ID data from the barcode on the installed meter, and the start read, CHEC desires to update service location information by having the Bidder capture the GPS co-ordinates of the installed endpoint. Where meters are located in basements or in areas where satellite signal may not be possible, the closest co-ordinates will be collected once communication has been established.

Bidder's declaration of compliance: **Fully Compliant**

Bidder's Functionality Statement: The WFM system is capable of automatically capturing the GPS location of the installed meter, and this information is automatically recorded within the assigned service order. The GPS device is integrated (i.e. not a separate device), and is accurate to within 3m (10 feet).

2.4.4 Grounds For Disqualification

It is a requirement of this RFP document that the Bidders submitting proposals for evaluation complete a compliancy spreadsheet which will attest to the Bidder's compliance with the Health and Safety Policies and Procedures as outlined in Section 3.1 *CHEC Health and Safety Policies and Procedures*. In addition to having read this section, and all applicable subsections, the Bidder agrees that their company's own Health and Safety Policies will, at minimum, meet CHEC's Safety Policies, and that their bid response will provide the information to properly satisfy the requirements of Section 3.2 *Safety* (and applicable subsections), and that the content of the response is consistent with the policies being agreed to here.

NOTE: Failure to complete these compliancy documents (found within the Pricing and Compliancy Spreadsheet; tab named "CHEC_BidderCompliancy", or where compliancy has been misrepresented, CHEC reserves the right to disqualify the Bidder from contention of the RFP process.

2.5 Clarifications

Upon the issuance of this RFP to Bidders, and continuing through the submission date, all questions or other communications with CHEC shall be by email only, with CHEC's authorized representative, whose contact information is provided in Section 2.4 *Submission of Bids*.

CHEC will respond to the question in writing, with both the question and response provided to each Bidder that has declared intention to bid according to Section 2.2 *Intention to Bid*. No response will be made to questions submitted after November 7, 2008 (as per Section 2.1 *Key Dates*).

2.6 Modifications or Withdrawals of Bids

A Bidder may modify or withdraw its bid by written declaration, provided that the declaration is received by the CHEC contact specified in Section 2.4 *Submission of Bids* prior to the time specified for the submission of bids (the due date). Following withdrawal of its bid, a Bidder may submit a new bid, provided that such new bid is received by CHEC prior to the due date. The last bid received by CHEC shall supersede and invalidate all bids previously submitted by the Bidder.

CHEC may modify any provision of the Request for Proposal at any time prior to the due date. Such modifications may be made in the form of addenda, which will be issued simultaneously to all prospective Bidders that have declared their intention to bid. No addenda will be issued within five calendar days of the due date.

2.7 Bid Inconsistencies

Any provisions in Bidder's proposal that are inconsistent with the provisions of this Request for Proposals, unless expressly described in the proposal as being exceptions or alternates, are deemed waived by the Bidder. In the event the Order is awarded to Bidder, any claim of inconsistency between the proposal and this RFP will be resolved in favour of this RFP unless otherwise agreed to in writing by CHEC.

2.8 Post-Bid Meeting

CHEC reserves the right to invite any or all Bidders to make an in-person presentation on the proposed smart meter installation services.

2.9 Proposal Evaluation

CHEC will evaluate proposals using an internal scoring method that weights various parameters to give the CHEC team insight into the strengths of each proposal relative to CHEC member utility's needs.

Answers to sections 3 through 7 will represent 40% of the total weighting of the RFP. Pricing submitted will represent 60% of the total weighting of the RFP. Bidders will be selected for further discussion based on the Team's judgment, developed using the scoring method. CHEC's internal scoring method values the following proposal attributes (order of presentation does not reflect priority):

Figure 1: Proposal Evaluation Criteria

Proposal Evaluation Criteria	Section	% Total Points
Safety	3	
Project Overview	4	
Bidder Information	5	
Installation Services	6	
Service Offering / Capability		
Inventory Control		
Scheduling and Coordination		
Reporting		
Used Meter Disposal Handling		
A to S Adaptor Installation		
Meter Base Repairs		
Tamper / Theft		
Customer Communications	7	
Call Centre		
Pre Canvas		
Perspectives expressed by reference utilities		
Section 3 through 7 inclusive:		**40%**
Pricing Weighting:		**60%**
Total		**100%**

2.10 Award or Rejection

Issuance of this RFP does not constitute a commitment by CHEC to award a winning Bidder or purchase products or services offered in response to this RFP. CHEC reserves the right to reject any or all bids. CHEC will not reimburse Bidders' costs to respond to this RFP.

2.11 Execution of the Order

If requested by CHEC, the successful Bidder must assist CHEC in preparing the Purchase Order, which will be governed by the Terms and Conditions set out herein, or others as mutually agreed by the parties. The successful Bidder must duly execute the Purchase Order within ten (10) days after receipt and return it to CHEC. Failure of the successful Bidder to duly execute and return the Order, together with any other required documents will constitute a breach of contract by such Bidder and entitle CHEC to award the Order to any other Bidder, in addition to all other rights and remedies of CHEC.

2.12 Freedom of Information

Proposals submitted to CHEC become the property of CHEC and, as such, are subject to the *Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, c. F.31, as amended.

2.13 Ownership of Data

CHEC shall own all data used and/or collected by any systems being utilized to perform the services. Data shall not be used for any purpose without the approval of CHEC.

2.14 Conflict of Interest

The Bidder is required to disclose in its Submission and on an ongoing basis thereafter any conflict of interest, real or perceived, that exists now or may exist in the future, with respect to this RFP, any resulting contract, or in relation to CHEC or their affiliates.

2.15 Proposal Forms

Within this section, there are two forms required for submission. The first form is found in Section 2.15.1 *Intention to Bid Form*; the intention of this form is to allow the Bidder to provide a standard email response to CHEC to notify CHEC of the Bidder's intent to respond to the RFP.

2.15.1 Intention to Bid Form

Bidders intending to respond to this RFP should notify the contact, using the contact information provided in Section 2.4 *Submission of Bids*, according to the time line as established by Section 2.1 *Key Dates,* by sending an email with the following content inserted:

INTENTION TO BID NOTIFICATION FORM

PROPOSAL NO. 2008-1024

Intention to Bid:
Please allow this email to represent "__Insert Company Name Here__" intention to respond to CHEC RFP#: 2008-1024.

Contact for communication regarding bid: ________________________________
Contact phone number: ________________________________
Contact email address: ________________________________

We acknowledge the requirement that our company meets the minimum Safety Requirements as outlined in Section 3. Our proposal will include the required compliance statements and documents to properly express our ability to meet these requirements. We also acknowledge the Submission Deadline is 3:00 pm Eastern Time on November 21, 2008.

2.15.2 RFP Submission Form

The procedure to be utilized for the RFP Submission form is to print the following pages, and include them with the RFP submission, which should be addressed to the designated contact listed in Section 2.4 *Submission of Bids*, and which should be submitted according to the time line as established by Section 2.1 *Key Dates*.

RFP SUBMISSION FORM

Cornerstone Hydro Electric Concepts (CHEC)

Proposal Number: **RFP# 2008-1024**

FOR: Installation Services

THIS PROPOSAL IS SUBMITTED BY:____________________

ADDRESS:

TELEPHONE: FAX NO.:

BIDDER G.S.T. No.:

PERSON(S) SIGNING ON BEHALF:____________________________(print)

POSITION(S) OF THE PERSON(S):__________________________________(print)

To Cornerstone Hydro Electric Concepts, Hereafter called "Owner":

I/WE ____________________________________ the undersigned declare:

1. THAT no Person(s), Firm or Corporation other than the one whose signature(s) of whose proper officers and the seal is or are attached below has any interest in this Proposal or in the contract proposed to be taken.

2. THAT this Proposal is made without any connections, knowledge, comparison of figures or arrangements with any other company, firm or person making a Proposal for the same work and is in all respects fair and without collusion or fraud.

   THE Bidder insures that no Owner and or employee of the CHEC group, is, or has become interested, directly or indirectly, as a Contracting Party, Partner, Stockholder, surety or otherwise howsoever in or on the performance of the said contract, or in the supplies, work or business in connection with the said contract, or in any portion of the profits thereof, or of any supplies to be used therein, or in any monies to be derived there-from.

3. THAT the several matters stated in the said Proposal are in all respects true.

4. THAT I/WE have carefully examined the requirement(s), as well as all sections of the document including Instruction to Bidders, Project Overview, Installation Services, Proposal Forms, and Appendices relating thereto, prepared, submitted and rendered available by CHEC and hereby acknowledge the same to be part and parcel of any contract to be let for the work therein described or defined.

5. THAT I/WE do hereby Propose and offer to enter into a contract to deliver all work as described or implied therein including in every case freight, duty, exchange, G.S.T. and P.S.T. in effect on the date of the acceptance of Proposal, and all other charges on the provisions therein set forth and to accept in full payment therefore, the sums calculated in accordance with the actual measured quantities and unit prices set forth in the Proposal herein.

6. THAT Addendum/Addenda No. ___ to ___ inclusive relate to the said contract and Bidder hereby accepts and agrees to the same as forming part and parcel of the said contract.

7. THAT additions or alterations to or deductions from the said contract, if any, shall be made in accordance with the prices stated in the Schedule of Items of Unit Prices in strict conformity with the requirements of the Contract.

8. THAT this offer is irrevocable and open to acceptance until the formal contract is executed by the awarded Bidder for the said requirement(s) or Sixty (60) working days, and unit prices for as long as stated elsewhere in the document, whichever event first occurs and that CHEC may at any time within that period without notice, accept this Proposal whether any other Proposal has been previously accepted or not.

9. THAT the awarding of the contract, by CHEC is based on this submission which shall be an acceptance of this Proposal.

10. THAT I/WE also understand that CHEC reserves the right to accept or reject all or part of this Proposal or any other and also reserves the right to accept other than the lowest Proposal.

The undersigned affirms that he/she is duly authorized to execute this Proposal.

BIDDER'S SIGNATURE AND SEAL: ______________________

NAME: ______________________
(Please Print)

POSITION: ______________________

WITNESS SIGNATURE: ______________________

WITNESS NAME: ______________________
(Please Print)

POSITION: ______________________

(If Corporate Seal is not available, documentation should be witnessed)

DATED AT THE ______________________ THIS ________
(City/Town) (Day)

DAY OF ______________________ 2008.
(Month)

Section 3: Health and Safety

3.1 CHEC Health and Safety Policies and Procedures

Sections 3.1.1 *CHEC Health and Safety Policy* through Section 3.1.6 *Health and Safety Legislation that Applies* are requirements for which compliance are required in order for any external contractors to be permitted to provide services to CHEC. As such, a Statement of Compliancy pertaining to each section is required, and a form has been provided within the Pricing and Compliancy Spreadsheet as outlined in Section 2.4.2 *Pricing and Compliancy Spreadsheet*.

Section 3.2 *Safety* is where the Bidder is provided the opportunity to demonstrate, through the submitted documents, that their own internal Health and Safety Policies, either meet, or exceed those outlined in Section 3.1 *CHEC Health and Safety Policies and Procedures*. Bidders that cannot meet, or exceed those requirements outlined in Section 3.1 *CHEC Health and Safety Policies and Procedures*, or that do not (or cannot) provide a completed Compliancy statement is eligible for disqualification from the evaluation process.

3.1.1 CHEC Health and Safety Policy (C)

CHEC members proclaim that the Health & Safety of each employee is of vital importance in the successful operation of the utility.

Our objective is to develop a keen sense of health & safety awareness in each and every employee and thereby prevent personal illness/injury and damage to property and equipment.

Management is responsible for providing a healthy and safe work environment and for training employees to ensure that they can perform their duties safely.

It is the duty and responsibility of every employee to work safely with equal concern for themselves, co-workers and the public.

It is our collective responsibility to ensure compliance with legislated requirements of Occupational Health & Safety Act.

It is our commitment to provide a safe and healthy work environment by reducing hazards that cause accidents and injuries.

3.1.2 CHEC Field Service Personnel Health and Safety Conditions (C)

Based on the nature of the work being procured through this RFP, and in accordance with the CHEC Health and Safety Policy, the following items shall be received prior to the start of work:

- Acknowledgement from the contractor that they are aware of and agree to adhere to the terms and conditions.
- WSIB Certificate
- NEER firm summary statement
- Liability Insurance
- Health & Safety Policy / Program
- Staff Competency List
- Confirmation of applicable EUSA training
- Documentation of injury experience

- WHMIS MSD documentation for any hazardous materials used in the job
- Equipment Fitness List

3.1.3 CHEC Field Service Personnel Health and Safety Policy (Basic Procedures) (C)

In accordance with CHEC Operating Policies and Procedures, all installers performing work such as that being procured through this RFP shall:

- Wear rubber gloves, Category 2 Fire Retardant Clothing or better
- Class 'O' rubbers for voltage checks
- Hard Hats
- Flash glasses
- Face Shields
- Safety boots
- Ensure meter voltage and type is correct
- Observe safe limits of approach
- Observe wiring to determine if a back feed could be present, e.g. capacitors, standby generator, co-generator
- Not remove meter if meter base is damaged or not secure
- Use meter puller

3.1.4 CHEC Health and Safety Policy: Field Service Personnel (C)

In accordance with CHEC Operating Policies and Procedures, all installers performing field service work shall be:

- Responsible for knowing, understanding and working in compliance with the appropriate safety legislation, EUSA rules, CHEC member utility rules, policies, procedures and safe work practices that apply to the work.
- Responsible for using and wearing at all times the appropriate personal protective and safety equipment required for the work.
- Responsible for using the equipment, materials, protective devices in the proper and safe manner.
- Responsible for participating in, and holding tailboard conferences as required in order to safely complete the work.
- Responsible to participate in any coaching sessions, training, safety meetings, and company general meetings in order to ensure continued competence in the most up-to-date rules, policies, procedures and safe work practices.
- Responsible for reporting all hazardous conditions or equipment defects to the supervisor immediately, fill out the proper documentation and assist with corrective action.
- Responsible to ensure loss incidents and potential loss incidents are reported to the supervisor immediately. Provide preliminary details, fill out the proper documentation and participate in the incident investigation as required.
- Responsible to follow the Internal Responsibility System.
- Responsible to take every precaution reasonable in the circumstances for the protection of the safety of fellow employees.

3.1.5 CHEC Health and Safety Policy: Supervisor/Manager (C)

In accordance with CHEC Operating Policies and Procedures, all Supervisors and/or Managers of Field Personnel shall be:

- Responsible for knowing, understanding and ensuring that work is done in compliance with the appropriate safety legislation, EUSA rules, each CHEC member utility's rules, policies, procedures and safe work practices that apply to the work.
- Responsible for identifying the job hazards, determining the solutions or barriers required to provide safe working conditions and communicating this information to all workers under their supervision.
- Responsible for ensuring all job information such as tailboard conference sheets, traffic plans, vehicle and equipment inspection sheets are filled out properly and returned to the office as appropriate.
- Responsible for holding documented tailboard conferences as required and ensuring appropriate worker participation in order to complete the work safely. Responsible for directing the work in a safe manner.
- Responsible for using and ensuring all crew members use and wear at all times the appropriate personal protective and safety equipment required for the work.
- Responsible for using and ensuring all crew members use the equipment, materials, and protective devices in a proper and safe manner.
- Responsible to ensure loss incidents and potential loss incidents are reported to CHEC members immediately. Provide preliminary details, fill out the proper documentation and participate in the incident investigation as required.
- Responsible to report workers who do not comply with their health and safety responsibility, for corrective action by their supervisor.

3.1.6 Health and Safety Legislation That Applies (C)

The Provincial, Federal and Municipal acts & regulations that must be adhered to include, but are not necessarily limited to, the following:

- Bill C45
- Transportation of Dangerous Goods Act , 1992
- Ontario Occupational Health & Safety Act & Regulations
- Ontario Regulation 632/05 – Confined Spaces
- Ontario Regulation 213/91 – Construction Projects
- Ontario Regulation 835-846 – Designated Substances
- Ontario Regulation 851 – Industrial Establishments
- Ontario Regulation 860 – WHMIS
- Ontario Highway Traffic Act & Regulations
- Ontario Regulation 595 – Commercial Motor Vehicle Inspections
- Ontario Regulation 4/93 – Hours of Service
- Ontario Traffic Manual
- Ontario Regulation 22/04 – Electrical Distribution Safety
- Electrical Operations Rule Book (EUSA Rules)
- Electrical Safety Code

3.2 Safety (CI)

CHEC's number one requirement will always remain the health and safety of its employees and customers. In addition to stating compliance to CHEC Health and Safety Policies as outlined in Sections 3.1 *CHEC Health and Safety Policies and Procedures*, the Contractor shall ensure that all installation personnel complete all required training for meter installation, meter testing, and for the installation and testing of any other endpoint devices to be installed. CHEC will be expected to work with the Contractor to identify specific gaps in training and testing. The Contractor will communicate to CHEC members how it will complete all training in advance of any installations taking place. The Bidder's ability to provide the required training (according to CHEC's requirements) for successful on-time deployment must be approved and properly documented by both CHEC's Project Manager and Health and Safety Officer.

To reflect a similar commitment to Health and Safety, all contracted vendor's policies and procedures manuals will contain comprehensive documentation (as a complement to completed training programs) regarding On-The-Job Safety, Emergency Plans, Accident/Investigation Procedures, and Contact Numbers for any possible incident occurrences, as well as Hazard Assessment Identification and Control, (including (but not limited to) Dangerous Animals, Slips/Trips/Falls, Workplace Violence, Confined Spaces and Unsafe Meter Bases).

Included with the Bidder's response document should be current documentation regarding WSIB clearance.

Additionally, all contracted field service employees will provide to CHEC's designated Health and Safety Officer (prior to commencement of services), proof that contracted employees:

- Hold a valid driver's license,
- Hold valid driver's insurance,
- Have provided a Driver's Abstract to their employer,
- Have provided a Criminal Background Check to their employer.
- Provide proof of WSIB CAD Experience (WSIB Clearance Certificate)
- Provide proof of EUSA Electrical Safety and Awareness Course
- Provide proof of EUSA Electric Power Meters Course
- Health and Safety Training Program
- Environmental Management System Training
- Utilize Tailboard Conference/Tailgate Safety Talks
- Conform to Technical, Quality Assurance, and other CHEC member specific training requirements
- Have received WHMIS Training
- Have any necessary First Aid Training/CPR Training
- Have received Customer Service Training
- Have completed In-field Training
- Comply with CHEC member utility's Contractor Checklist

Note: There is a requirement (as per Section 2.4.4 *Grounds For Disqualification*) for Bidders to declare compliancy with the appropriate safety regulations. Failure to do so will make the Bidder's response eligible for disqualification from the remainder of the evaluation.

3.2.1 Safety Policies (I)

CHEC believes that none of its meter sites presents a threat to the personal safety of field workers. It is the responsibility of the Bidder to ensure the safety of their staff, and to ensure that the necessary precautions are taken to ensure the security of any required tools.

i. Bidders shall describe their training and safety program.
ii. Bidder will provide their Health and Safety Policies and Procedures manual, complete with listing of assigned equipment, and required PPE. Documentation on the competency of staff utilizing PPE will also be provided.
iii. Bidder will provide the Emergency procedures that are provided to their installation staff; and indication that relevant staff have been trained on the procedures.
iv. Bidder should provide their Joint Health and Safety Committee meeting schedule/frequency, and membership.
v. Bidder should provide details on the number of staff that meet the safety requirements as outlined.

CHEC reserves the right to review and approve training materials and methods before the start of deployment. Bidders should note that CHEC Safety Committee members will be conducting their own random audit process on installation staff.

3.2.2 Unsafe Meter Bases (I)

Bidders should provide details on their procedures for the handling of meter sites where installation is delayed by unforeseen circumstances such as required infrastructure upgrade, accident, or customer objection. Bidders will describe notification procedures and method for tracking the status of such sites.

Acceptable security precautions are to be maintained during all installation activities. The Installer will identify, report and resolve unsafe conditions on a daily basis or as they are identified according to established safety policies. In the case of electrical or mechanical hazards, these shall be reported to CHEC immediately.

Some meter bases have been deemed unsafe. The Contractor shall not attempt, at any time, to remove a meter that has been deemed unsafe. When encountered, the Contractor will be required to identify unsafe meter bases in the WFM handheld device using the appropriate codes and notify CHEC's Installation coordinator. Bidders shall include, within their response, a description of the procedures that are invoked upon discovery of an unsafe meter base, as well as description of the pre-installation inspection protocols which may result in the discovery of an unsafe meter base.

Section 4: Project Overview

Section 4 of the Bidder's proposal shall contain a statement of recognition that the Bidder understands the CHEC's schedule for deployment and the deployment territory, and that they are providing a bid response with the intention of performing the required services for CHEC. Given the diverse nature of the service territory, and that there are Smart Meter Deployments occurring across the province, Bidders have the opportunity within this section to demonstrate, through submitted documentation/statements, how they will be able to accommodate the unique requirements of CHEC (i.e. staffing across the area, for the timelines projected).

4.1 CHEC Anticipated Schedule for Deployment (C)

Section 2.1 *Key Dates* shows the anticipated start date for deployment, and the end date required by CHEC. Within this time frame, the successful Bidder will be required to install the quantity of Smart Meters documented in Section 4.4 *Installation Volumes*. (The statement of recognition that is required for Section 4: *Project Overview* should include recognition of these timelines, and the Bidder's ability to accommodate them).

Please refer to Appendix "C" for a CHEC pre-approved deployment schedule, which is complete with meter delivery schedules. The Installer shall develop and maintain an installation schedule to ensure installations are completed on time and on budget without interfering with the meter-reading schedule.

4.2 Approved Hours of Installation (C)

Meter installations are to take place between the hours of 8:30 a.m. to 4:30 p.m., Monday to Friday. In special circumstances, extended hours of 8:00 a.m. to 8:00 p.m. and/or Saturday work may be considered by CHEC members if required to accommodate the timelines as communicated within Section 2.1 *Key Dates*. No Meter installation is to take place on statutory holidays observed by CHEC.

The Installer shall develop and maintain an installation schedule to ensure installations are completed on time and on budget without interfering with the meter-reading schedule. The Installer can modify the work schedule with permission of CHEC members to best meet installation goals and project milestones.

4.3 CHEC Deployment Territory (C)

Maps for CHEC's service territories have been provided in Appendix "B" to better illustrate the service territory within which the residential Smart Meter deployment will take place. It is anticipated that all Smart Meter installations being procured through this RFP will take place within these territories.

4.4 Installation Volumes (C)

CHEC projects that of the required 110,000 residential Smart Meter installations, 101,937 will be installed by the successful Bidder (with the exception of any reported safety concerns).

In addition to the following table, CHEC has provided within Appendix "B" the cycle volumes for certain of CHEC member's service territory.

Single Phase Meters	Indoor		Outdoor	
	S-base	P/A-base	S-base	P/A-base
Centre Wellington	377	0	4,609	0
Collus	23	32	11,512	339
Innisfil	50	0	11,740	233
Lakefront	1,273	621	5,919	5
Lakeland	649	49	6,416	118
Midland	180	45	5,203	45
Orangeville/Grand Valley	444	94	7,727	96
Orillia	262	305	9,000	0
Parry Sound	442	9	2,185	15
Rideau St. Lawrence	569	821	3,155	90
Wasaga	52	12	9,653	130
Wellington North	381	77	2,025	276
Westario	175	107	14,400	0

4.4.1 Electrical Contractor

CHEC shall provide a qualified Electrical Contractor to complete repairs to customer plant deemed necessary based on the identified safety concerns.

4.5 CHEC Meter Deliveries (C)

Westario Power will require that the Installer manage the meter inventory on their behalf, and release meters to the field service staff from an Installer managed Meter Depot location. The Pricing and Compliancy spreadsheet allows for bidders to enter pricing for this requirement.

The remaining CHEC members are also interested in this service as well, and Bidders are asked to provide pricing for their service territories as well. In the event that CHEC members (with the exception of Westario Power) decide not to implement this option, the following meter depot locations will be used. Under this arrangement, for the duration of this deployment, meter installers will be required to pick up, and drop off, their inventory at the following address, between the hours of 7:30 am to 5:00 pm:

CHEC Utility Member	Meter Depot Location
Centre Wellington Hydro Ltd:	**730 Gartshore Street, Box 217 Fergus, ON N1M 2W8**
COLLUS Power Corp:	**43 Stewart Road, Box 189 Collingwood, ON L9Y 3Z5**
Innisfil Hydro Distribution Systems Ltd:	**2073 Commerce Park Drive Innisfil ON L9S 4A2**
Lakefront Utilities Inc:	**207 Division Street, Box 577 Cobourg, ON K9A 4L3**
Lakeland Power Distribution Ltd:	**5 - 45 Cairns Cres. Huntsville, ON P1H 2M2**

Midland Power Utility Corporation:	**16984 Highway 12, P.O. Box 820** **Midland, ON L4R 4P4**
Orangeville Hydro Limited **and Grand Valley Energy Inc:**	**400 'C' Line, Box 400** **Orangeville, ON L9W 2Z7**
Orillia Power Distribution Corporation:	**360 West Street South** **Orillia, ON L3V 6J9**
Parry Sound Power Corporation:	**125 William Street** **Parry Sound, ON P2A 1V9**
Rideau St. Lawrence Distribution Ltd:	**985 Industrial Road, Box 699** **Prescott, ON K0E 1T0**
Wasaga Distribution Inc:	**950 River Road, Box 20** **Wasaga Beach, ON L9Z 1A2**
Wellington North Power Inc:	**290 Queen Street West, Box 359** **Mount Forest, ON N0G 2L0**
Westario Power Inc:	**24 Eastridge Road** **Walkerton, ON N0G 2V0**

All pick-up and delivery of meters by the Installer shall be at the designated facility for the term of this contract unless otherwise agreed upon. Field Service Personnel shall pick up new meters and equipment and return the removed meters, in the new cartons, once daily to a designated location provided by CHEC. No meter shall be returned without an associated transaction record and must be in actual cartons from new installs duly marked.

The Installer will be responsible for all meters from time of signing out of inventory/warehouse until successfully installed. Information regarding inventory in the Installer's custody shall be provided to CHEC upon request.

Note: For deployment within the outlying areas, arrangements will be made between the successful Bidder, and CHEC members, to minimize travel time for the Installers. For pricing purposes, Bidders should assume minimal impact to the work day (i.e. meter pick-up and drop-off will not impact the 8:30 am to 4:30 pm work day).

Section 5: Bidder Information

5.1 Experience (I)

i. How many years has the Bidder been in business?
ii. How long has the Bidder been providing installation services?
iii. The Bidder should describe their primary line of business and the percentage of business derived from the installation of meters.
iv. The Bidder should describe the organization and provide an organization chart of the team or department that would have specific resources used in the deployment of AMI. (Include the number of personnel assigned to installation services and project management of the AMI installation.)
v. Identify and describe any AMI/AMR project where the installation schedule has been delayed as compared to the original Statement of Work per the contract when signed and describe the causes, current status and plans to address the delay(s). (If you lack AMI/AMR experience please provide for the most comparable projects you have completed to date).

5.2 Company Size and Location (I)

What is the current size (number of employees), turnover rates for last three (3) years, and location(s) of the Bidder's company?

5.3 Financial Statement (I)

What is the current financial condition of the Bidder's company? Provide supporting documentation and annual reports for the last three years. If the company is privately held, supply sufficient information to document the company's financial status.

5.4 Subcontractors (I)

Does the Bidder intend to subcontract any component, service or support requested in this RFP? If so, indicate which components, services or support and identify the subcontractors.

5.5 References (I)

Provide a list of at least three (3) references (contact names and phone numbers) from companies that have used the Bidder's proposed services in the past three (3) years. Please indicate the number of meters installed and type (gas, water or electric).

5.6 Litigation (I)

Bidder will indicate if there are any anticipated or pending lawsuits or any litigation within the past five (5) years or bankruptcy filings within the past ten (10) years.

5.7 Environmental Policy (I)

CHEC recognizes environmental protection as a guiding principle and key component of sound business performance. CHEC is committed to providing quality customer service in a manner that ensures a safe and healthy workplace for our employees and minimizes our potential impact on the environment. We not only operate in compliance with, but also strive to exceed all relevant federal, provincial, and municipal environmental legislation; and we will strive to use pollution prevention and environmental best practices in all we do.

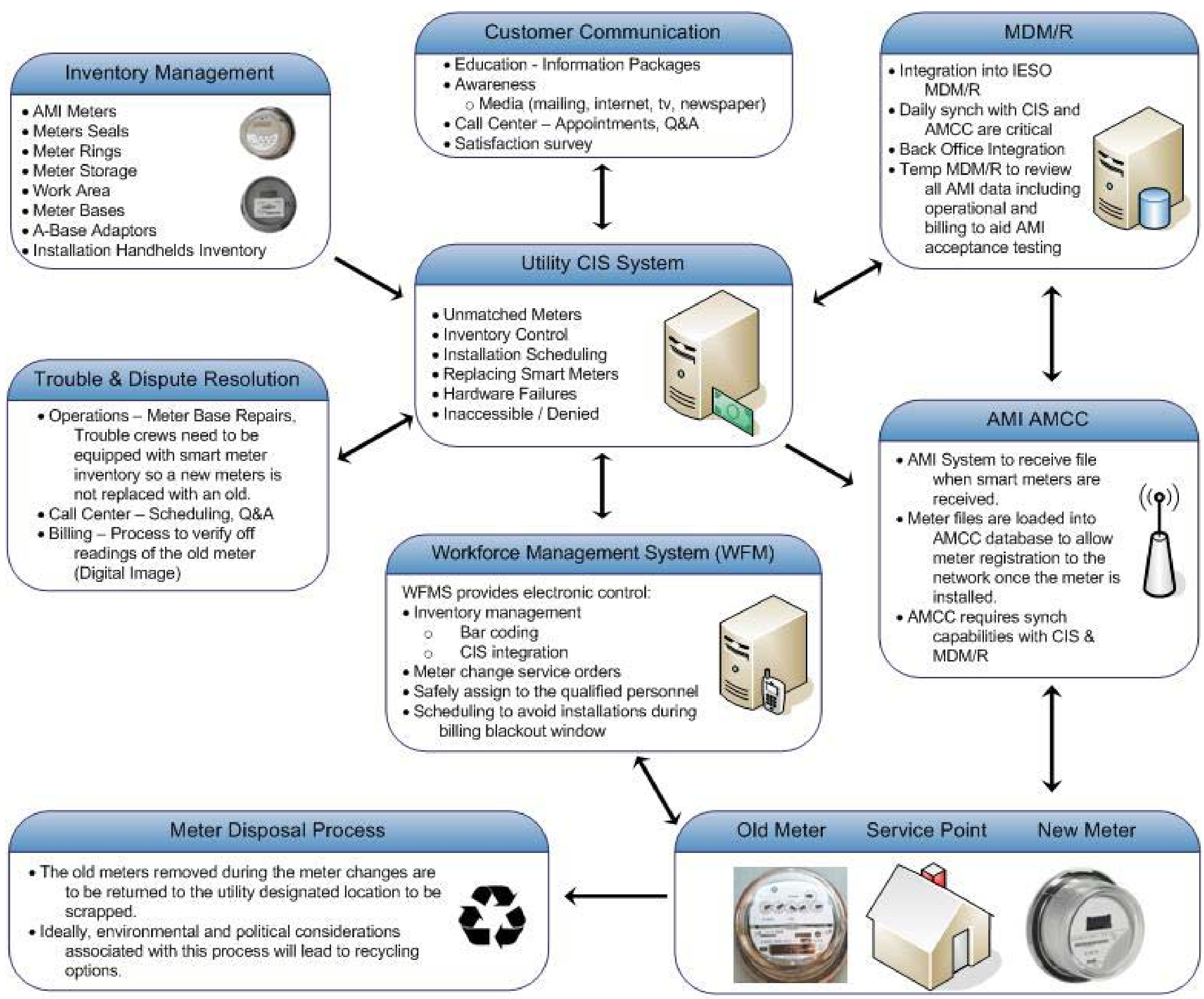
Bidder should indicate if they have a written environmental policy statement, whether the policy statement includes a commitment to continual improvement of environmental performance, whether the company has documented environmental performance objectives/targets and implementation plans, and what their three most significant environmental performance objectives/targets are. In addition, Bidders should describe the extent to which employees understand, accept, and share the environmental values of the company, and how the company uses environmentally friendly products in its day-to-day operations.

Section 6: Installation Services

With the execution of this province wide mandate, we would stress the importance of providing our customers with the highest level of customer service possible. Figure 3 is a high level view of the work flow process that encompasses the Smart Meter Installation process. Bidders will note the requirements for:

- Proper receipt and inventory of meters
- Change out order creation
- Change out order completion
- Workforce management system to update CIS when orders are completed
- Inventory update to MDR system
- Need for bar coding or digital image of changed meter to prevent disputes
- Ongoing reading of Smart Meter system
- Ongoing maintenance of inventory in MDR

Figure 3: High Level Work Flow of Installation Process



6.1 Installation Overview (C)

The Smart Meter installer will be responsible for installing Smart Meters on all single phase, network and self contained meter installations for all residential and small commercial (under 50 kW) locations. The Contractor will not be required to install any transformer rated installations or polyphase meters. The total number of non-transformer rated customer electric meter installations being procured through this RFP can be found in Section 4: *Project Overview*.

CHEC will perform upgrade or repair to electric services found to require this during the Smart Meter inspection or installation process. Installer will notify CHEC as rapidly as practical when such requirement poses a hazard to field workers. Bidders will describe notification procedures and method for tracking the status of such sites.

- **All Field Personnel must be well groomed, and in full uniform with the required CHEC member utility photo identification.** Installer will not issue daily assignments to Field Personnel who do not comply with this policy, and the appropriate disciplinary action should follow.
- All Field Personnel will strictly adhere to CHEC inventory control processes, including the proper use of any associated Workforce Management System.
- All Field Personnel will ensure that any required ancillary meter supplies (seals, rings, etc) are acquired prior to beginning the days' work (to ensure travel time is minimized).
- Meter installations are to take place between the hours of 8:30 am to 4:30 pm Monday to Friday. No meter installations are to take place on statutory holidays observed by CHEC member utilities.
- CHEC will provide meter seals and other security hardware to be placed on the meter by the Contractor when installing the meter. A-to-S Base meter adapters will be provided by CHEC for A-Base meter change outs.
- As part of providing exemplary customer service, the Bidder is expected to handle customer complaints that are related to installation services and provide customer assistance to resolve issues resulting from installation negligence to the satisfaction of CHEC, ensuring all claims are reported to CHEC. Claims not resolved after 10 days should be reported to the appropriate CHEC member utility for resolution.

6.1.1 Minimum Competencies (C)

Before installing meters the Installer shall ensure the Field Service Personnel are customer service oriented, have flexible work hours and are bonded, and the Installer shall maintain a process to ensure these requirements are met.

The Installer shall operate within specific procedures and operating conditions in adherence with procedures and training that CHEC will provide. Upon conclusion of the CHEC utility specific training, it will be the Installer's responsibility to ensure that new employees receive the same level of training as those employees which receive the training through CHEC.

6.1.2 Suggested Installation Procedure (CI)

The Installer shall follow the following process for the installation of all Smart Meters:

i. The Field Service Representative (FSR), as a minimum, will visit the site as the first attempt to install the Smart Meter.
ii. Prior to installation, FSR will knock on the door prior to removing the meter to advise the customer of the work to be performed and pending power outage.
iii. If the first attempt is not successful due to inability to access the meter, the FSR shall visit

the customer site a second time on a different day, at a time of day at least (2) hours different from the first visit, to perform the Smart Meter installation.

iv. If necessary, a third visit attempt shall be made by the FSR.

v. If necessary, the Contractor shall also attempt to reach the customer by telephone, to schedule access to the meter.

vi. If necessary, a second telephone attempt shall be made.

vii. If three (3) visits and two (2) phone contacts have been exhausted without successful access to the meter, the Installer may declare the account non-installable and refer it to CHEC for resolution.

viii. All customer contact, interaction and communications shall meet CHEC standards.

ix. The customer shall be accommodated with a scheduled appointment with a specific day and time within a 1 hour window arranged and scheduled by the Installer, through their call centre which will be open between the hours of 8:00 am and 7:00 pm.

x. The utility will provide a list of known customers on Medic Alert as per the Control Centre list.

xi. Installer will deliver upon completion of meter change an information “Drop” package for the customer.

xii. Installer will ensure the install site is left “clean” (i.e. under no circumstances is the customer site to be left littered with any installation associated debris)

xiii. Should an incident occur at the property (i.e. Broken meter jaws), the contractor shall remain at the property until the contract electrician or CHEC staff can arrive at the property.

When every meter on a route has either passed the field installation operating test or been declared non-installable by Installer, that route will be declared ready for Route Acceptance.

With regards to the installation procedure above, Bidders are requested to discuss:

a) concurrence with suggested procedure
b) concurrence with suggested definition of non-installable account
c) PPE utilized by Field Service Personnel

6.1.3 Installer Vehicles (C)

Installer will provide Field Personnel a vehicle to be used for installation services. The requirement for a uniform fleet of vehicles is to minimize the call centre traffic associated with customer inquiries related to the appearance of Field Service Personnel. Field Service Personnel are expected to maintain vehicles in respectable condition (i.e. reasonably clean, presentable and without excessive damage) as well as perform and document a daily vehicle safety check. Vehicles will be properly marked to indicate the company providing services. The meter installation vehicles are to be capable of carrying a minimum of 60 boxed meters (15 boxes). Removed meters are to be placed in the boxes that the new meters were shipped in and returned to the utility designated location.

The Installer shall be responsible for all related parking fines and parking fees through the course of the Agreement.

CHEC members shall provide their corporate logo and “Under Contract” signage, which must be affixed to all vehicles used by the Contractor. The Contractor may display its own corporate logo as approved by CHEC. Preference will be given to vehicles that are otherwise unmarked (ie. Display no other significant signs or marking such as a rental agency logo).

6.2 Pre-Installation Inspection (CI)

The pre-installation inspection shall include knocking on the door of the customer premise to determine if the site is occupied, and to inform occupants of the imminent, brief power interruption. Meter Installers will utilize the appropriate PPE and Equipment (including, but not limited to, arc/flame resistant uniforms (Category 2), meter installer identification, etc.) at all times.

The pre-installation inspection shall discern whether:

- The work site is unsafe to complete the assigned task (unsafe meter base, confined space, etc.)
- There is tampering or energy diversion evident at the meter site
- The existing physical equipment and installation do not conform to applicable codes
- The existing meter and installation is transformer rated.
- An electrical hazard may arise upon installation of the Smart Meter

If ANY of the above five (5) conditions exist, the Contractor shall perform no work at the site, but shall notify the Installer Project Manager, who shall notify the CHEC contract Administrator. It is possible that the pre-installation will fail to detect a hazard, such as tension (frost pull) on the underground secondary service conductor that will move broken meter socket jaws when the meter is removed. The Installer shall comply with CHEC procedures that apply if, at any time during the Smart Meter process, a serious hazard arises.

6.2.1 Tampering (C)

The Installer is responsible for reviewing electric metering facilities for obvious signs of tampering and interference, including jumpers, stopped meters (if not disconnected), un-metered load on the line side of the meter, damage caused by apparent attempts to open the meter, or any other situation where tampering/interference appears to have been involved. If the Installer suspects tampering or diversion, no work (or further work) shall be performed at that site. The Installer shall notify CHEC on a daily basis of all power diversion, tampering or interference-related situations that might impact revenues to CHEC.

Any meters that are scheduled to be replaced and are disconnected using disconnect sleeves or have a Programmable Service Interrupter unit installed will be re-installed by the Installer after the meter change unless the utility directs otherwise. All meters that are disconnected with sleeves, must be installed on the new Smart Meter with tabs on the bottom lugs only to ensure the meter will continue to act as a communication hop.

6.2.2 Power Diversion (I)

During the process of installing Smart Meters, CHEC wishes to discover meter installations (if any) where there is meter tampering and/or energy diversion. As such, a financial incentive of an agreed to amount per proven occurrence will be paid to the Installer for each verified instance of meter tampering and/or power diversion.

Bidders are requested to provide any information pertaining to this or other incentive programs which are thought to ensure high service levels from Field Service Personnel.

6.3 Scheduling & Coordination (I)

Coordination among the flow of materials, installer labour, customer response/acceptance, and CHEC member utility data updates is a principal determinant of whether the Smart Meter installation proceeds on-time and within budget. A well-coordinated project can run smoothly and finish on time. No unusual mandatory work rules or wage constraints apply to the work solicited in this RFP.

The Bidder should propose normal work hours to CHEC for its approval. Installers are to be available for work on evenings and weekends and for special-need installations. The Bidder should be prepared to modify the work schedule to best meet installation goals and project milestones set by CHEC.

Bidders are requested to provide information regarding the manner in which work is assigned, including such details as number of outside installs per day assigned, number of indoor installs assigned per day, and the capabilities of the Bidder's WFM system with regards to routing, personnel qualifications to avoid assigning work to the wrong people/trucks, etc. The Installer shall provide a detailed deployment schedule that accomplishes CHEC's meter installation targets. The Installer is responsible to manage the installation schedule to ensure the satisfaction of CHEC. The Installer is responsible to design, propose, and possibly implement a plan to advance the installation services timeframe in the event that the project schedule is delayed in any way.

The Installer is responsible for responding to calls from CHEC members regarding the loss of service and other high priority problems associated with installations on an expedited basis. CHEC will do everything within its control to aid the progress of the Installer in meeting the goals of this Agreement. However, minor delays in productivity due to day-to-day operational issues management will occur and are considered typical and normal in the course of regular business. (ie. Software irregularities, computer downtime, wireless communications gaps or emergencies.)

6.4 Project Management (CI)

The Contractor shall designate a Project Manager who shall have the authority to handle and resolve any disputes or contractual issue with CHEC member utilities.

The Project Manager is expected to spend sufficient time on the project and the project site to identify any areas that are not fully meeting the stated requirements, and manage corrective actions to bring the results within said requirements.

The Project Manager's role will be to coordinate activities among the Contractor, the Smart Meter provider and the various functional areas within member utilities. Problem resolution will be high on the Manager's agenda. The Project Manager will maintain clearly defined levels of installation problem categories and associated escalation levels to facilitate quick recognition and resolution of problems. The Project Manager will involve CHEC utilities as appropriate to resolve issues in a timely manner.

Section 3.2 *Safety* and Section 6.1.1 *Minimum Competencies* requires that the meter installer's meet certain qualifications, and that the installation service provider provide CHEC members with certain documentation. The Project Manager will facilitate satisfaction of these requirements,

Bidders should provide suggested procedures for Problem Resolution / Problem Escalation.

6.4.1 Quality Assurance (I)

The Installer's policies/procedures shall include an integrated quality control / quality assurance program:

Bidders will describe the proposed approach to staffing the field deployment, including:

a. Positions to be filled by permanent employees of Bidder
b. Positions to be filled by temporary employees or contractors
c. Qualifications of employees or contractors
d. Training of employees or contractors
e. Strategy for monitoring the work quality of employees or contractors and correcting any encountered deficiencies

CHEC members understand that there may be several AMI deployments occurring concurrently across Ontario to accommodate the Provincial mandate, and requires the Bidders written acknowledgement that the appropriate staff will be dedicated to the requirements of the CHEC deployment.

6.4.2 Installation Field Audit (CI)

The Installer's Project Manager / Supervisor will conduct random audits of staff in the field to check for safety compliance as well as for the quality of work completed by the meter installers. The Contractor's Project Manager / Supervisor will, on a weekly basis, randomly check a minimum of 2% of the sites for quality control. All results are to be reported to CHEC on a weekly basis. Items to be audited include at minimum:

- Proper line and load wiring associations on bottom connected installations
- Identification of hot metering installations when a main switch exists at a service entrance and is supposed to provide isolation to the meter and it is actually on the load side of the meter
- Validation of crossed units, on multi-unit dwellings
- Work order data validation and transfer to each utility

6.4.3 Service Quality Standard (C)

All work shall be completed according to the agreed schedule using milestones. Checkpoints and corrective action on slipped timelines shall be assessed on an interval of duration no longer than (2) weeks.

In keeping with the stringent safety requirements of CHEC member utilities, as communicated herein, Bidders will strive for no less than zero preventable safety incidents and accidents.

Failure to report any safety incident or accident to a CHEC member utility will put the Contractor in breach of the Agreement and may disqualify them from competing for future service contracts and may result in the termination of the present Agreement without a notification period.

6.5 Workforce Management (WFM) System

The Workforce Management (WFM) system plays an integral role in the success of the project acting as the main system responsible for work order completion, project reporting and task management, and ensuring safety for meter installations. Due to the critical nature of the WFM, it is imperative that the 3rd party installation service provider be comfortable with the functionality of the WFM system. For this reason, CHEC will require that the Bidder provide their own WFM as part of their service package.

It is a fundamental requirement that this system is in place with a functional interface to CHEC member utility CIS systems prior to the start of deployment. CHEC is interested in the functionality provided as part of the WFM system; information will be requested as part of Section 6.5 *Workforce Management (WFM) System* and associated subsections. A compliancy statement is required which will have Bidder's acknowledge proficiency with an electronic WFM system, and a commitment to ensuring integration with CHEC members' back office systems prior to project commencement (as per Section 2.1 *Key Dates*). Bidders should include, with their submission, the file layouts that CHEC members would be required to interface their CIS system with.

Provided below are the billing systems that are currently in use at CHEC member utilities which the proposed WFM system will be required to interface with.

- Advanced (2.1)
- Harris (5.2.19)
- Harris Northstar (6.2.9)
- SAP (R3 v 4.6c)

CHEC will provide to the vendor, in electronic format, information concerning the locations that will require meter changes / installations (i.e. customer name and contact information, service location address and location number along with an expected completion date). By way of electronic WFM the Installer will add to this record, the final meter read from the mechanical meter at the time of removal. The Installer will also take a photograph of the old meter, showing its dials prior to removal. This photo will be date and time stamped and the file name recorded in the data record associated with the specific installation.

6.5.1 WFM System Overview (I)

Within the Pricing and Compliancy spreadsheet, CHEC has provided a tab labelled WFM_Functionality, within which Bidders are requested to submit information pertaining to their WFM system, specific to the different devices that may be utilized with the system.

Below we have provided an example of a completed WFM system functionality matrix. Bidders are requested to complete this spreadsheet for all devices that are compatible with the WFM software platform. In addition to acquiring the information regarding a variety of functionality, CHEC looks to understand any potential functionality differences between devices being offered as part of a solution. If multiple devices are possible CHEC utilities may opt to purchase more than one type of device. In this case it would be important to understand if any functionality is lost in moving from one device to another.

Completion of the chart may satisfy some of the following sections. However the following sections provide Bidders with the opportunity to supply additional supporting information which may differentiate their product.

Workforce Management (WFM) Functionality

WFM Functionality	WFM Bidder: Sample (S/O)	Add-On Cost
Devices		
Handheld	S	
Tablet	O	$1200/tablet
Signature tool	O	Standard with tablet
Touch Screen	O	Standard with tablet
Printing Capabilities	O	$600/print device
Connectivity		
Real Time	O	cost to interface
Batch upload (offline storage)	S	
Carriers		
Bell	S	
Rogers	S	
Telus	S	
Multiple Network Roaming	O	$300/comm card
Utility RF	NA	
Other	NA	
Existing Utility Interfaces		
T&W	S	
SAP	S	
SPL	O	cost to interface
Other	S	
Forms		
Template only	S	
Customized	S	
Other	NA	
Reporting		
Fat Client	No	
Thin Client	Yes	
Canned	S	
Customized	S	
Safety	S	
Inventory	S	
Completed vs. Schedule	S	
Route Summary	S	
Problem Installs	S	
Other	S	programming fees
Operational Tools*		
Bar Code Scanner	S	
GPS Recording	S	
Camera	NA	
GPS Tracking of Workers	NA	
Scheduling		
Automated dispatch	S	
Dispatching based on qualifications & Equipment	S	
Map based dispatching	O	
Street level routing	O	
Other	NA	

Bidders are required to complete chart for their WFM product. If more than one product is offered, copy the columns as required.

Bidders are required to specify an S or an O to represent standard functionality vs. optional functionality. If the optional functionality is available only at an incremental cost, this must be specified.

NA may be used to represent Not Available.

*For Operational Tools, please indicate in the associated documentation whether this functionality is integrated with the WFM device, or whether they are separate tools.

6.5.2 Dispatching (CI)

In support of the priority which CHEC members place on safety, CHEC is interested in the ability to assign worker qualifications to their field staff to assist in the dispatching of orders to only the personnel with the qualifications required to complete the work. This may be achieved through assigning qualifications to staff, or toolsets to trucks, or any other of a variety of methods. Details should be provided regarding all the safety features inherent to the WFM system.

Bidders are asked to provide detailed information regarding the dispatching of work orders. The manner in which work orders are sorted/listed (i.e. by customer, location, schedule, etc) is critical in realizing efficiencies with the assignment of field services.

If GPS capabilities are inherent to the system, and are integrated into the dispatch process, Bidders are asked to provide explanation, and screen shots of the views that are possible for the dispatcher. In addition to the mapping of orders, CHEC members are interested in accessing the real time location of their workers to assist in the completion of on demand requests (i.e. service disconnect / reconnect, outage restoration, etc). Details regarding this functionality are requested.

In addition to the manner in which the dispatcher accesses information, Bidders are asked to explain the ease with which the field service worker (and any associated options) can sort work. If GPS capabilities exist, and are integrated with the sorting of work while in the field, screen shots of the views possible for the field service worker are requested.

6.5.3 Data Management & Integrity (I)

The Installer shall record and retain the meter identification information and the register read of the removed meter, the meter identification information and the register read of the installed Smart Meter using a handheld WFM system equipped with a barcode reader.

The Installer shall maintain an effective process to assure the quality of the electronic data records and transactions. All field data shall be pre-filled on orders. The Installer shall place emphasis on quality data management from the beginning of the training, and will remain responsible for correcting errors in data collected during the installation process.

Data quality (including Meter Reads) shall be accurate 99.9% of the time over the course of the project. The Installer shall collect data from specified collection locations and transfer data in a specified electronic file format for use by CHEC in accordance with a schedule that will be provided by the utility.

6.5.4 WFM Handheld Device (I)

CHEC would like to understand the device being utilized by the contractor. Information should include format of device (tablet, PDA, laptop, phone, etc.), how many orders per day the handheld device can manage (i.e. how many can be downloaded), and what the expected daily battery life is of the device.

6.5.5 Installation Hours (i.e. WFM Charging) (CI)

CHEC’s policy for installation hours are that installations should be occurring between the hours of 8:30 am and 4:30 pm. CHEC prefers that there are no evening installs. Saturday installs are acceptable with proper planning (minimum 1 week notice) and staffing of the call center. This should be a last resort for installation backlog, so as not to inconvenience customers. Installer would be required to provide a minimum number of installers in this instance to ensure that it is a productive day (i.e. CHEC members will have to pay overtime to warehouse staff).

6.5.6 Digital Imaging (CI)

The handheld Workforce Management Equipment must be able to take a picture with a resolution no less than 3 Mp of the removed meter. The Installer will take a photograph of the old meter, showing its dials. This photo will be date and time stamped and the file name recorded in the data record associated with the specific installation.

Digital imaging is performed to mitigate the risk associated with Dispute Resolution. If the WFM system allows for read validation which might be used in conjunction with the Digital Imaging process, Bidder should provide details.

6.5.7 GPS (CI)

In addition to installing the meter, capturing the LAN ID and Meter ID data from the barcode on the installed meter, and the start read, CHEC desires to update service location information by having the Bidder capture the GPS co-ordinates of the installed endpoint. Where meters are located in basements or in areas where satellite signal may not be possible, the closest co-ordinates will be collected once communication has been established. Details (including GPS accuracy) are requested regarding this functionality.

6.5.8 Inventory Control (CI)

Given the volume of daily meter installations that will be performed, maintaining accurate control of inventory will be critical. All sealed meter deliveries will be sent to the CHEC location and loaded into inventory via an import into CIS.

Daily workflows will need to be established that have an assigned point of contact for the installation vendor to verify and sign-out the meters required each day for installation in the field. At the end of each day or at start of the next shift, the same point of contact will verify the meters that were not installed are recorded in inventory ensuring adequate controls are in place to manage the assets.

Managing the inventory of essential hardware is an important step in keeping the installation process moving while controlling costs.

i. The Workforce Management system will be capable of utilizing bar code scanning for recording newly deployed meters.
ii. Bidders will describe methods used to track inventory of all essential ancillary supplies needed to support the deployment including any associated smart meter devices and installation tools, meter seals, meter rings, meter adaptors, security devices, etc. Bidders should provide details on how their company will ensure that accurate data is provided back to CHEC members and their back office systems.

6.6 Reporting Requirements (CI)

The CHEC Project Manager will hold weekly meetings together with the Installer's Project Manager to review status, identify problems, and plan resolution. The Installer shall provide reporting (as per following subsections) to support these meetings. Where possible, reports should be generated from the WFM system, made possible by the daily data transfers identifying sites visited and completed.

Following is a sample of items that might be included in these reports:

i. Safety Issues;
ii. Bidders will describe installation problem categories and escalation levels, identifying the point at which the CHEC Project Manager will become involved;

iii. Inventory status;
iv. Installers will provide daily data transfers identifying sites visited and completed and providing work order data;
v. Bidders should supply automated reports regarding success/failure of daily installation targets;
vi. The Installer shall report progress, including numbers and percentages of meters installed, attempts to complete the installation process, appointments scheduled and completed and other pertinent installation data to CHEC on a weekly basis (if project plan timeline has been affected, the Installer will provide their plan which will put them back on schedule according to the originally submitted schedule);
vii. It is expected that the successful Bidder will invoice based on the data in the WFM system.

Bidder's should provide detailed information regarding the reporting functions that are possible through their WFM or other systems.

The Installer will provide all required equipment, along with the trained staff. The Installer shall be required to report all relevant data from the field to the CHEC Installation Coordinator. This includes, but is not limited to meter exchanges that cannot be completed because of access, physical space limitations, or safety reasons.

6.6.1 Reporting: Beginning of the Project (C)

In addition to any other data and reporting requirements outlined, the following report / information will be required at project commencement:

The Bidder will provide CHEC with a Project Plan that indicates the number of meter installers per week for the duration of the project as well as the meters to be installed per week. The Plan shall include contingency plans in the event the installation numbers fall behind the milestone schedule.

6.6.2 Reporting: Daily Reports (C)

In addition to any other data and reporting requirements outlined, the following reports and information will be required on a daily basis through the duration of the project:

The Bidder will identify, report and resolve unsafe conditions on a daily basis or as they are identified according to established safety policies, and report all tampering / interference related situations that might impact revenues, to CHEC on a daily basis.

6.6.3 Reporting: Weekly Reports (C)

In addition to any other data and reporting requirements outlined, the following reports and information will be required at weekly interval through the duration of the project:

The Bidder will provide CHEC members with project plan updates which include number of meters installed to date, and number of meters remaining to be installed. If behind schedule, Action Plans will be identified that are being used to bring the installation schedule back on track.

In addition, the Bidder shall provide details related to any identified unsafe conditions, safety issues, customer diversions, tampering.

6.6.4 Reporting: Bi-Weekly Reports (C)

In addition to any other data and reporting requirements outlined, the following reports and information will be required at bi-weekly intervals through the duration of the project:

The Bidder will provide CHEC member utilities with an invoice indicating: The number of meters installed, the number of identified and utility validated power diversions, the number of identified and utility validated unsafe meter installation sites, the month end invoice shall indicate the number of meters that didn't comply with the month-end target milestone installations.

6.7 Service Level Agreements (I)

Bidders should provide their standard Service Level Agreements, citing such measurable performance indicators as:

i. Outside Urban installation per week
ii. Inside Urban installation per week
iii. Installation Error rate
iv. Customer Claim rate

6.8 Installation Warranties (I)

The Bidder must state terms on guarantee of workmanship for all installation work performed under this contract.

6.9 Meter Disposal (I)

CHEC will be utilizing a Meter Disposal Vendor to properly, and in an environmentally sound manner, discard of the redundant meters. Should the Bidder desire to provide a Meter Disposal Labour rate, a line item has been added to Pricing Option 1 for this purpose. The Labour that would be required for this service would potentially be for the separation of glass covers from meters, and organization of meter packing supplies (cardboard, Styrofoam packing etc.) into the appropriate bins that would be provided by the Meter Disposal Vendor. CHEC would provide the work space for this service to be performed.

6.10 Water Meters (I)

NOTE: While this section does include an indicator (I), this section is not considered mandatory. There is no requirement that Bidders provide a response to this section.

Certain of CHEC members are interested in replacing existing water meter infrastructure with equipment which will be compatible with the AMI system being deployed. In all likelihood this will require a two stage implementation beginning with the replacement of existing remotes with radio modules. Upon conclusion of the replacement of exterior remotes, the utility will begin replacing meter heads where required. It is expected that the two stages will occur at different times due to the variation in work requirements.

CHEC members for which this work is applicable are interested in synergies and possible cost savings that may result through some combination of work schedules. As the decision regarding this work will be made through a separate procurement, the information that is requested here is purely informational and will not form part of the evaluation being conducted for the purposes of determining the best fit Installer for deployment of electric smart meters.

Information that may contribute to the future procurement includes:

i. Bidder experience with water projects (information submitted may include "suggestion" as to how to best structure work flow to minimally impact the electric deployment, while possibly realizing synergies and cost efficiencies)
ii. Bidder qualifications for water projects
iii. Bidder references for water projects

Bidders that are interested in being considered for this future work are required to:

a. Provide an email to the CHEC contact listed in Section 2.4 Submission of Bids. The email need only provide contact information and expression of interest in the future procurement process. This will ensure that interested bidders are included in the future process.
b. Provide the information requested in this section as part of their response. **As noted in this Section, responses will not be evaluated as part of the decision regarding Electric Smart Meter Deployment Installation Services.**

6.11 Ancillary Services (I)

CHEC members are interested in having the successful Bidder warehouse the AMI meters which have been received into utility inventory. The Pricing and Compliancy spreadsheet allows for bidders to provide pricing for this service through the Pricing Option 1 tabs, under the Ancillary Services section.

Westario Power **will require** this service. While the remaining CHEC members may not ***require*** this service, they are interested in possible efficiencies that may be realized through having the vendor provide this service (i.e. relaxed time of return for installers due to absence of time restrictions associated with the utility managed meter depot). Bidders are asked to provide pricing for warehousing services for both service areas.

CHEC members would like to reiterate to Bidders the importance of clearly specifying any conditions/assumptions that have contributed to their pricing. CHEC members have provided line items within the pricing tabs which may appear repetitive (i.e. GPS, Disposal labour, Imaging process, inventory management, etc), however this has been done intentionally to provide vendors with the flexibility to provide incremental pricing for all required services.

Section 7: Customer Communications

7.1 Call Centre Services (I)

Installer will be responsible for customer communications associated with gaining access to the customer's meter. CHEC recognizes that some accounts, despite extensive effort by Installer, may be non-installable for any of many reasons. CHEC members accept responsibility for installing smart meters at these non-installable accounts. Bidders will describe the customer communications plan, including;

i. Call Centre Services Overview (including hours of operation, and policies/procedures)
ii. Customer contact methods/strategies
iii. Appointment management (management of multiple sequential (unsuccessful until the last) customer contacts)
iv. Steps in achieving successful completion of Smart Meter installation
v. Definition of an non-installable account
vi. Customer claims administration
vii. Record keeping and coordination with CHEC Customer Service (CHEC member utilities are interested in understanding the tracking of Service Quality Indicators (SQIs) which may include (but not limited to) such indicators as inbound/outbound calls, appointments attempted/made, complaints, call waiting period, etc.)

Call operations shall be maintained from 8:00 a.m. to 7:00 p.m., Monday to Friday, and shall have a provision for taking calls using an automated method outside of the regular operating hours. CHEC recognizes that their agents may take calls, other than those for the purpose of appointments, once a phone number is provided to the customer. CHEC wishes the Contractor to transact only those calls related to the appointments to be fielded by their staff, and the operator for disposition shall direct all others to CHEC.

The Contractor shall provide in detail:

- The scripting for communicating with customers by phone
- A means of managing the collected customer information and appointments (i.e. managing ongoing coordination and customer communications related to the appointment and meter exchange by the Contractor)
- The fee structure for managing the customer communications for the expressed purpose of collecting appointment data

7.1.1 Communications Materials (I)

CHEC requires that communications materials be provided to the customer by their meter installers when the meter is inaccessible contain the phone number of the Contractor for future follow-up. The Contractor shall manage inbound phone communication to secure appointments for Smart Meter installations using a professional and courteous protocol that shall be approved by CHEC.

7.1.2 Customer Contact (I)

Each meter installer shall be responsible for customer communications associated with gaining access to customer meter. Meter installers will be provided with communications materials to be distributed to customers as part of the meter installation process.

Prior to beginning the meter exchange, each meter installer shall attempt to notify each customer by knocking on the front door and/or ringing the doorbell and waiting a minimum of (1) minute for a response. If the customer does respond, the Installer shall inform the customer of the meter exchange and short power interruption according to the standardized script provided by CHEC. If the customer does not respond, the Installer shall proceed with the installation of the Smart Meter.

7.1.3 Customer Information (CI)

Each meter installer shall provide each customer with communication materials as provided by CHEC, either in person, in the mailbox or through the mail slot. These materials are not to be left where they are readily visible to passers-by or may blow away or become damaged (i.e. rain damage).

7.1.4 Customer Complaints and Claims Administration (CI)

The Installer shall have a procedure to process and manage customer claims, arising from the provision of the Services pursuant to this Agreement, which will successfully resolve issues in a timely manner. All claims shall be reported to CHEC once the Installer has been made aware of the incidence. Claims outstanding over (10) days are to be reported to CHEC for resolution. The Installer shall have full accountability for customer claims and complaints, especially for the response to initial reports of half or full power outage following a Smart Meter change. This accountability applies regardless of the time of call and may fall outside business and work hours. CHEC crews and resources are prepared to aid the Installer in a resolution based on the initial findings of Field Staff if the call ends up being systemic rather than an oversight on the part of the Contractor. Additional compensation shall not be provided by CHEC to meet the Installer's obligations for after-hour response and site visits that are required to mitigate customer complaints.

7.2 Pre-Canvassing Service (I)

Pre-Installation Customer Information Packages are to be delivered to customers approximately 2 weeks before the scheduled meter replacement date. Customer Contact and Information Packages would be provided by CHEC.

As an option, Bidders that are able to provide input based on experience regarding suggested processes for Customer Communications that may take place prior to deployment are requested to do so. If possible, the Bidder should provide any marketing material that they may have used in the past that was found to be effective.

Section 8: Contract Terms and Conditions

8.1 General

This Agreement covers the general conditions under which the work shall be performed.

Bidder shall be aware and acknowledges that the work to be performed may be on or within close proximity to electrical apparatus that may be energized at normal potential and with normal current carrying capacity during the course of the work. This may involve the equipment or facilities being worked on directly, or equipment or facilities adjacent to the actual devices and location being worked on.

Bidder will under no circumstances replace anything except single phase meters.

8.2 Information to Contractors

Bidder represents that it has carefully examined the specifications and requirements of the municipality(s) having jurisdiction in the work location(s) and any other authorities having jurisdiction, and has thoroughly familiarized themselves with all permit, inspection and other requirements of all of these agencies and authorities.

Bidder will not rely solely upon any information or representations made or furnished by CHEC respecting the nature of the site conditions, the work to be performed or the quality of any materials to be used.

8.3 Approvals

Bidder shall work closely with the authorities having jurisdiction. Bidder shall satisfy all authorities on specific concerns on work permits. No permit costs have been included in this Agreement. Should the need for any permits arise, Bidder will invoice CHEC for the costs thereof.

8.4 Sub-Contractors

Bidder shall set out herein, all Sub-Contractors to be employed in the performance of the Agreement. No other Sub-Contractor shall be employed without the approval of CHEC.

8.5 Officials in Charge, Personnel, Employment Conditions

Bidder shall identify in Schedule “A”, prior to commencing work, a work site manager (the person on the job) who will be in charge of the work and all work sites, as well as an office official (officer, principle, or senior manager) at his central place of business who will be responsible for the work.

CHEC’s key contacts are also identified in Schedule “A”.

Bidder shall take every step to minimize a change of site manager during the course of the work, but when necessary, Bidder will make such change with an individual of similar or greater capability.

Bidder will provide conditions of employment in accordance with the Occupational Health and Safety Act, and the Employment Standards Act and their latest revisions, and any other statutory requirements in force and effect.

Bidder hereby agrees that no person shall be employed who is unfit to do the work or anyone unskilled to do the work assigned to him. Persons under the influence of intoxicating drugs or beverages shall be declared unfit.

Bidder agrees that for the purpose of the work to be undertaken, they will not discriminate in the hiring and implementation of labour against any person's gender, race, national origin, colour or religion.

8.6 Work Protection

Work protection from electrical hazards, where required, shall be applied for prior to beginning work and shall be consistent with the Electric & Utilities Safety Association's Protection Code, and upon review and acceptance by Bidder, CHEC requirements. Protections shall be surrendered at the end of each working day. In general, daily requests shall be available during CHEC normal working hours only.

Signalling and traffic protection shall be done according to the Occupational Health and Safety Act, the Highway Traffic Act, and CHEC requirements.

Only competent personnel shall work within the ten feet limit of approach for apparatus energized over 750 volts. CHEC Manager of Engineering and Maintenance shall have the sole discretion to determine such competence, but Bidder will assume full liability in respect of any such personnel, even if approved of by CHEC. Equipment, tools, and protective clothing shall be in accordance with the Electric Utilities Safety Act, the Occupational Health and Safety Act, and other authorities having jurisdiction.

8.7 Site Housekeeping

During the performance of the work, Bidder shall ensure that the work site is kept as neat and orderly as possible, in keeping with the nature of the work in progress. When work is interrupted for any length of time, or at the completion of the work, all waste material shall be removed and tools, equipment and surplus material shall be removed or stored or secured in a neat and safe fashion.

8.8 Term

The Agreement will terminate as per the agreed to contract dates. The Agreement may be extended on terms mutually agreeable to the parties.

8.9 Training and Safety

Before beginning installation of smart meters, all Bidder installers must receive the following training:

- E&USA Training for residential smart meter changes. Proof of training must be provided and approved by CHEC.
- CHEC Health and Safety orientation
- Work procedures and workforce management orientation

Bidder shall comply with all CHEC safety rules, when Bidder has reviewed and accepted such rules.

8.10 Schedule

Bidder shall submit, at such times as may reasonably be requested by CHEC, schedules which shall show the order in which it is proposed to do the work, with dates showing commencement and completion of the various parts of the work.

8.11 Public Relations

Bidder shall respect private property and do whatever necessary to prevent damage to landscaping, buildings, fences and other appurtenances on private property and where damage results will make restoration to the pre-damaged state. Public lands on rights of way shall be restored to the satisfaction of the authority having jurisdiction.

8.12 Identification

Bidder vehicles must be properly identified with the company name. Bidder employees must carry proper identification at all times.

8.13 Materials and Labour

Unless otherwise stipulated, the lump sum price or prices quoted in this Agreement shall include the furnishing of all of the Bidder designated supplied materials, supplies and equipment and the providing of all labour, construction tools and equipment, utility and transportation services necessary to perform and complete all the work required under this Agreement.

All designated material, major or minor, supplied by Bidder must be approved by CHEC prior to its installation. Any material supplied by Bidder and installed without CHEC approval will be replaced at Bidder's expense. Co-ordination of the delivery of materials shall be by Bidder. No claims will be considered due to late deliveries.

8.14 Working Hours

Unless otherwise stated, all labour and services under this Agreement will be performed during the hours of 8:30 am - 4:30 pm local time Monday through Friday, excluding statutory holidays (except for telephone call answer services). If for any reason CHEC requests Bidder to furnish any such labour or services outside of the hours of 8:30 am - 4:30 pm local time Monday through Friday, or on statutory holidays, any overtime or other additional expense occasioned thereby, such as repairs or material costs not included in this Agreement, will be billed to and paid by the appropriate CHEC member utility.

8.15 Taxes

CHEC agrees to pay the amount of any new or increased Canadian taxes or governmental charges upon labour or the production, shipment, sale, installation, or use of equipment or software which become effective after the date of this Agreement. If CHEC claims any such taxes do not apply to transactions covered by this Agreement, CHEC will provide Bidder with a tax exemption certificate acceptable to the applicable taxing authorities. CHEC to the extent required by applicable law, may retain and remit any withholding taxes on behalf of Bidder and provide evidence of that to Bidder. CHEC shall not be required to make any "gross up" payment to Bidder to compensate Bidder for such withholding.

8.16 Insurance Obligations

Bidder shall, at its own expense, carry and maintain in force at all times from the effective date of the Contract through final completion of the work the following insurance. It is agreed, however, that Bidder has the right to insure or self-insure any of the insurance coverage's listed below:

(a) Commercial General Liability Insurance to include contractual liability, products/completed operations liability with a combined single limit of CDN $5,000,000 per occurrence. Such policy will be written on an occurrence form basis.
(b) If automobiles are used in the execution of the Contract, Automobile Liability Insurance with a minimum combined single limit of CDN $5,000,000 per occurrence. Coverage will include all owned, leased, non-owned and hired vehicles.
(c) Where applicable, "All Risk" Property Insurance, including Builder's Risk insurance, for

physical damage to property which is assumed in the Contract.

(d) Workers Safety Insurance Board Insurance Coverage A - Statutory limits.

Prior to the commencement of the Contract, Bidder will furnish evidence of said insurance coverage in the form of a Memorandum of Insurance, and warrants that such coverage will be maintained for the duration of the Agreement, and that proof of maintenance will be routinely supplied.

Bidder will not issue coverage on a per project basis.

8.17 Hazardous Substances, Mould and Unsafe Working Conditions

8.17.1

CHEC has not observed or received notice from any source (formal or informal) of (a) Hazardous Substances or Mould, either airborne or on or within the walls, floors, ceilings, heating, ventilation and air conditioning systems, plumbing systems, structure, and other components of the Site, or within furniture, fixtures, equipment, containers or pipelines in a Site; or (b) conditions that, to CHEC's knowledge, might cause or promote accumulation, concentration, growth or dispersion of Hazardous Substances or Mould on or within such locations.

8.17.2

If any such materials, situations or conditions, whether disclosed or not, are in fact discovered by Bidder or others and provide an unsafe condition for the performance of the work or Services, the discovery of the condition will constitute a cause beyond Bidder's reasonable control and Bidder will have the right to cease the work or Services until the area has been made safe by CHEC or CHEC's representative, at CHEC's expense. Bidder will have the right to terminate this Agreement if CHEC has not fully remediated the unsafe condition within sixty (60) days of discovery.

8.17.3

CHEC members represent that they have not retained the Bidder to discover, inspect, investigate, identify, prevent or remediate Hazardous Substances or Mould or conditions caused by Hazardous Substances or Mould.

8.18 Warranty and Limitation of Liability

8.18.1

Bidder will have all work performed by appropriately trained and experienced personnel in a workmanlike manner consistent with industry standards and applicable law. Bidder will replace or repair any work Bidder provides under this Agreement that fails within the warranty period (one) 1 year because of defective workmanship or Bidder supplied materials, except to the extent the failure results from CHEC negligence, or from fire, lightning, water damage, or any other cause beyond the control of Bidder. This warranty applies to all work Bidder provides under this Agreement, whether or not manufactured by Bidder. The warranty is effective as of the date of installation.

8.18.2

The warranties set forth herein are exclusive, and Bidder expressly disclaims and CHEC expressly waives all other warranties, whether written or oral, implied or statutory, including but not limited to, any warranty of workmanship, construction, merchantability or fitness for a particular purpose, with respect to the services, equipment, and materials provided hereunder. Bidder will not be liable for any property damage, personal injury, loss of income, emotional distress, death, loss of use, loss of value, adverse health effect or any special, incidental, indirect, speculative, remote, consequential, punitive, or exemplary damages, arising from, or relating to, this limited warranty or its breach.

8.18.3

Bidder makes no representation or warranty, express, implied or otherwise, regarding Hazardous Substances or Mould. Bidder will have no duty, obligation or liability, all of which CHEC expressly waives, for any damage or claim, whether known or unknown, including but not limited to property damage, personal injury, loss of income, emotional distress, death, loss of use, loss of value, adverse health effect or any special, consequential, punitive, exemplary or other damages, regardless of whether such damages may be caused by or otherwise associated with defects in the Services, in whole or in part due to or arising from any investigation, testing, analysis, monitoring, cleaning, removal, disposal, abatement, remediation, decontamination, repair, replacement, relocation, loss of use of building, or equipment and systems, or personal injury, death or disease in any way associated with Hazardous Substances or Mould.

8.19 Indemnity

Bidder agrees to indemnify and hold CHEC and its agents and employees harmless from all claims for bodily injury and property damages to the extent such claims result from or arise under Bidder's negligent actions or willful misconduct in its performance of the work required under this Agreement, provided that such indemnity obligation is valid only to the extent (i) CHEC gives Bidder prompt notice in writing of any such claims and permits Bidder, through counsel of its choice and Bidder's sole cost and expense, to answer the claims and defend any related suit and (ii) CHEC gives Bidder the authority and reasonable assistance and access to all applicable information in its possession, at Bidder's expense, to enable Bidder to defend such suit. Bidder will not be responsible for any settlement without its written consent, which consent shall not be unreasonably withheld or delayed. Bidder will not be liable for loss or damage caused by the negligence of CHEC or any other party or such party's employees or agents. This obligation will survive termination of this Agreement. Notwithstanding the foregoing, CHEC agrees that Bidder will not be responsible for any damages caused by Mould or any other fungus or biological material or agent, including but not limited to property damage, personal injury, loss of income, emotional distress, death, loss of use, loss of value, adverse health effect or any special, consequential, punitive, exemplary or other damages, regardless of whether such damages may be caused by or otherwise associated with defects in the Services.

8.20 Limitation of Liability

8.20.1

Subject to: (1) Bidder's obligations under the above indemnity (s. 8.19), (ii) a breach of its confidentiality or privacy obligations, (iii) breach of applicable law; or (iv) intentional or willful misconduct, in no event will Bidder be liable for any special, incidental, indirect, speculative, remote, consequential, punitive or exemplary damages, whether arising out of or as a result of breach of contract, warranty, tort (including negligence), strict liability, mould, moisture, indoor air quality, or otherwise, arising from, relating to, or connected with the services, equipment, materials, or any goods provided hereunder.

8.20.2

Notwithstanding anything to the contrary herein, Bidder's total liability arising out of or as a result of its performance under this agreement will not exceed the amount of this agreement.

8.21 Excusable Delays

Bidder will not be liable for damages caused by delay or interruption in Services due to fire, flood, corrosive substances in the air, strike, lockout, dispute with workmen, inability to obtain material or services, commotion, war, acts of God, the presence of Hazardous Substances or Mould, or any other cause beyond Bidder's reasonable control (the "Force Majeure Event") provided that Bidder: (i) promptly notifies the other Party immediately and in detail of the commencement and nature of such a cause; (ii) promptly develops a workaround strategy if one is reasonably available; and (iii) uses all commercially reasonable efforts to render performance in a timely manner utilizing to such end all resources reasonably required in the circumstances, including obtaining supplies or services from other sources if same are reasonably available and to otherwise resume service to the applicable standard. A failure by a sub-contractor or other agent to perform shall only be considered a Force Majeure Event if the failure by that sub-contractor or agent to perform is due to a Force Majeure Event suffered by that sub-contractor or agent and such sub-contractor or agent is taking the same actions as are required by Bidder under this Section in respect of a Force Majeure Event. The benefit of this section shall not apply to the performance or an obligation which is thirty (30) or more days in default. In the event of any such delay, date of shipment or performance will be extended by a period equal to the time lost by reason of such delay.

8.22 Dispute Resolution

With the exception of any controversy or claim arising out of or related to the installation, monitoring, and/or maintenance of fire and/or security systems, the Parties agree that any controversy or claim between Bidder and CHEC arising out of or relating to this Agreement, or the breach thereof, will be settled by arbitration, conducted in accordance with the Arbitration Rules of the Canadian Commercial Arbitration Center. Any award rendered by the arbitrator will be final, and judgment may be entered upon it in accordance with applicable law in any court having jurisdiction thereof. Either party can terminate for cause without the obligation to engage in dispute resolution, mediation or arbitration.

8.23 Acceptance of Contract

This proposal and the pages attached will become an Agreement upon signature above by Bidder and CHEC. The terms and conditions are expressly limited to the provisions hereof, including Bidder's General Terms and Conditions attached hereto, notwithstanding receipt of, or acknowledgment by, Bidder of any purchase order, specification, or other document issued by CHEC. Any additional or different terms set forth or referenced in CHEC's purchase order are hereby objected to by Bidder and will be deemed a material alteration of these terms and will not be a part of any resulting order.

8.24 Miscellaneous

8.24.1

This Agreement represents the entire Agreement between CHEC and Bidder for the work described herein and supersedes all prior negotiations, representations or Agreements between the Parties related to the work described herein.

8.24.2

None of the provisions of this Agreement will be modified, altered, changed or voided by any subsequent Purchase Order or other document unilaterally issued by CHEC that relates to the subject matter of this Agreement. This Agreement may be amended only by written instrument signed by both Parties.

8.24.3

This Agreement will be governed by the law of the province where the work is to be performed.

8.24.4

Any provision or part of this Agreement held to be void or unenforceable under any laws or regulations will be deemed stricken, and all remaining provisions will continue to be valid and binding upon Bidder and CHEC, who agree that this Agreement will be reformed to replace such stricken provision or part thereof with a valid and enforceable provision that comes as close as possible to expressing the intention of the stricken provision.

8.24.5

CHEC may not assign its rights or delegate its obligations under this Agreement, in whole or in part, without the prior written consent of Bidder. Bidder may assign its right to receive payment to a third party.

8.24.6

Bidder will provide services in accordance with the attached work scope documents and the terms and conditions herein, which form a part of this Agreement.

8.24.7

The parties are independent contractors and no other relationship is intended. Nothing herein shall be deemed to constitute either party as an agent, representative or employee of the other party, or both parties as joint venturers or parties for any purpose to create a fiduciary relationship between the parties. Neither party shall act in a manner that expresses or implies a relationship other than that of an independent contractor. Each party shall act solely as an independent contractor and shall not be responsible to third parties for the acts or omissions of the other party. Neither party will have the authority or right to represent or obligate the other party in any way except as expressly authorized by this agreement.

8.24.8

If Bidder is delayed in its performance of the work due to the delayed performance or non-performance of CHEC or its suppliers, CHEC shall notify Bidder one (1) week in advance. In the event Bidder is notified (1) one week in advance, Bidder shall relieve CHEC of all costs except for the following: In the event Bidder incurs any costs in retaining staff or recruiting and staffing a new position as a result of the delay then CHEC will reimburse Bidder at its actual documented costs incurred plus 10%. Bidder shall invoice CHEC no more than weekly for such reimbursement and CHEC shall pay such invoices within the terms of this Agreement. All such invoices will itemize the costs incurred and proof will be provided to the extent possible.

8.25 Terms of Payment

Subject to Bidder’s approval of each CHEC member utility’s credit, payment terms are as follows:

Progress Payments: Bidder will invoice monthly for all materials delivered to the job site or to an off-site storage facility and for all installation, labour, and services performed, both on and off the job site. CHEC agrees to pay the full amounts invoiced, less holdback, upon receipt of the invoice at the address specified by CHEC. Invoices not paid within thirty (30) days of the invoice date are past due and accrue interest from the invoice date to the date of payment at the rate of one percent (1%) per month, compounded monthly.

Holdback: CHEC will not withhold, as holdback, a greater percentage than is withheld from CHEC under a prime contract, if applicable. CHEC will pay all holdback to Bidder within 30 days after Bidder's work is substantially complete.

Suspension of work: If Bidder, having performed work per Agreement requirements, does not receive payment within thirty (30) days after submission of a Bidder invoice, Bidder may suspend work until CHEC provides remedy unless CHEC provides evidence disputing such amount is owing.

8.26 Work by Others

8.26.1

Unless otherwise indicated, the following items are to be furnished and installed by others: electric wiring and accessories, all in-line devices (including but not limited to flow tubes, hand valves, orifice plates, orifice flanges, etc.), pipe and pipe penetrations including flanges for mounting pressure and level transmitters, temperature sensors, vacuum breakers, gauge glasses, water columns, equipment foundations, riggings, steam tracings, and all other items and work of like nature. Automatic valve bodies and dampers furnished by Bidder are to be installed by others.

8.26.2

Services Bidder will provide under this Agreement specifically exclude professional services which constitute the practice of architecture or engineering unless specifically set forth by CHEC. CHEC or Owner will specify all performance and design criteria that Bidder will follow in performing work under this Agreement. If professional design services or certifications by a design professional related to systems, materials, or equipment is required, such services and certifications are the responsibility of others.

8.27 Delivery

Delivery of equipment not agreed on the face hereof to be installed by or with the assistance of Bidder will be F.O.B. at Bidder's factory, warehouse, or office selected by Bidder. Delivery of equipment agreed on the face hereof to be installed by or with the assistance of Bidder will be C.I.F. at site of installation.

8.28 Damage or Loss

Bidder will not be liable for damage to or loss of equipment and software after installation.

8.29 Termination

A party may terminate this Agreement for cause if the other party defaults in the performance of any material term of this Agreement, or fails or neglects to carry forward the work (in the case of Bidder) in accordance with this Agreement, after giving the other party written notice of its intent to terminate. If the defaulting party has not, within seven (7) business days after receipt of such notice, remedied such deficiencies, the other party may terminate this Agreement.

8.30 Changes in the Work

CHEC, without invalidating the Agreement, may direct the Contractor to perform extra work or make changes in the work, provided that all changes or additions form an inseparable part of the contracted work. The contractor shall make such changes or additions only after receipt of written instructions to do so from CHEC. If such changes or additions cause an increase or decrease in the cost of the Agreement, or in the time required to complete the Agreement, an equitable adjustment shall be made and the Agreement shall be modified accordingly by a Change Order in writing.

When a change is ordered, CHEC and the Contractor shall execute a change order before any change order work is performed. Any increase or decrease in the contract price and the time required for the completion of the contract work due to a change order shall be specifically set out in the change order. All terms and conditions contained in the Agreement shall be applicable to change order work. The amount of any increase or decrease shall be added to or subtracted from the contract price as appropriate.

8.30.1

A Change Order is a written order signed by CHEC and Bidder authorizing a change in the work.

8.30.2

CHEC may request Bidder to submit proposals for changes in the work, subject to acceptance by Bidder. If CHEC chooses to proceed, such changes in the work will be authorized by a Change Order.

8.31 Acceptance of the Work

CHEC designated representative will determine if any work has not been performed in accordance with this Agreement.

Upon receipt of notice by Bidder that the work is ready for final inspection and acceptance, CHEC will make such final inspection and issue acceptance within five (5) business days (except for work performed in the first thirty (30) days of the Agreement, in which case it shall be ten (10) business days). Acceptance will be in a form provided by Bidder, stating that to the best of CHEC's knowledge, information and belief, and on the basis of CHEC's on-site visits and inspections, the work has been fully completed in accordance with the terms and conditions of this Agreement. If CHEC finds the work unacceptable due to non-compliance with a material element of this Agreement, which non-compliance is due solely to the fault of Bidder, CHEC will notify Bidder in writing within the five (5) business days (or ten (10) business days, as applicable) setting forth the specific reasons for non-acceptance. Failure to respond shall result in cancellation of the Agreement. Any payment then made will be based on proration, per unit, quantities of acceptable work performed, less costs assessed by CHEC for correction of deficiencies and noted issues. Nothing in this Section 8.31 will be construed to require that CHEC indemnify and hold harmless the Bidder from claims and costs resulting from Bidder's negligent actions or willful misconduct.

8.32 Confidentiality and Privacy

"Confidential Information" means all information relating to either Party or to such Party's business, products, sales, customers, trade secrets, technology or financial position to which access is obtained or granted hereunder, which when disclosed to the other Party is marked or otherwise designated as confidential, provided, however, that Confidential Information shall not include any data or information which: (i) is or becomes publicly available through no fault of the other Party; (ii) is already in the rightful possession of the other Party prior to its receipt from the other Party as evidenced by documentation; (iii) is independently developed by the other Party as evidenced by documentation; (iv) is rightfully obtained by the other Party from a third party whose lawful right to provide such data or information is evidenced by documentation; (v) is disclosed with the written consent of the Party whose information it is; or (vi) is disclosed pursuant to a Canadian court order or other Canadian legal compulsion.

8.33 Definitions

8.33.1

"Hazardous substance" includes all of the following, and any by-product of or from any of the following, whether naturally occurring or manufactured, in quantities, conditions or concentrations that have, are alleged to have, or are believed to have an adverse effect on human health, habitability of a Site, or the environment: (a) any dangerous, hazardous or toxic pollutant, contaminant, chemical, material or substance defined as hazardous or toxic or as a pollutant or contaminant under state or federal law, and (b) any petroleum product, nuclear fuel or material, carcinogen, asbestos, urea formaldehyde, foamed-in-place insulation, polychlorinated biphenyl (PCBs), and (c) any other chemical or biological material or organism, that has, is alleged to have, or is believed to have an adverse effect on human health, habitability of a Site, or the environment.

8.33.2

"Mould" means any type or form of fungus or biological material or agent, including mould, mildew, moisture, yeast and mushrooms, and any mycotoxins, spores, scents, or by-products produced or released by any of the foregoing. This includes any related or any such conditions caused by third parties.

8.33.3

"Covered Equipment" means the equipment covered by the Services to be performed by Bidder under this Agreement, and is limited to the equipment included in the respective work scope attachments.

Request for Proposal

Operational Data Store
RFP 2008-1114

November 14, 2008

Cornerstone Hydro Electric Concepts

Table of Contents

Section 1: Background

1.1 Introduction

To create a conservation culture in Ontario and make the Province a North American leader in energy efficiency, the Government has taken action to facilitate a number of key initiatives, including the introduction of flexible, time-of-use pricing for electricity, and a target reduction in Ontario's energy consumption of 5% by 2007.

The attached documentation sets out the procedural and technical requirements for the submission of proposals to Cornerstone Hydro Electric Concepts (CHEC), for its Operational Data Storage (ODS) requirements as per the enclosed specifications; as well as the substantive contractual terms that govern the relationship between parties upon award of the contract.

CHEC members have been working collaboratively through the planning and preparation stages for the Smart Meter Initiative. CHEC is an association of electricity distribution utilities modeled after a cooperative to share resources and proficiencies as the Ontario electricity industry continues its transformation.

The mission of CHEC is to be recognized as the premier LDC Cooperative in the province, by meeting or exceeding member expectations through the sharing of services, opportunities, knowledge and resources. The values of CHEC include the sharing of resources, both intellectual and technical, enabling members to deliver value to their customers and shareholders ensuring competitiveness in the marketplace. Together the mission and value statements represent lofty but attainable goals for CHEC members. Collaboratively CHEC represents over 110,000 residential end points in Ontario and is comprised of the following member utilities:

Centre Wellington Hydro Ltd.
COLLUS Power Corp.
Grand Valley Energy Inc.
Innisfil Hydro Distribution Systems Ltd.
Lakefront Utilities Inc.
Lakeland Power Distribution Ltd.
Midland Power Utility Corporation
Orangeville Hydro Limited
Orillia Power Distribution Corporation
Parry Sound Power Corporation
Rideau St. Lawrence Distribution Ltd.
Wasaga Distribution Inc.
Wellington North Power Inc.
Westario Power Inc.

1.2 Provincial Context for Project

As part of its energy conservation effort, the Ontario government has made a commitment to replace all existing meters (5 million) with smart meters by 2010. Phase One utilities have fulfilled their commitments to install 1 million smart meters by Dec 31, 2007 which assisted the government in exceeding their interim goal of 800,000 by Dec 31, 2007. Focus now shifts to the Phase Two implementation of a Smart Meter Network.

The underlying premise behind the provincial mandate to install these meters is to educate customers on their consumption habits and implement new rate structures that will encourage load shifting and conservation of energy, thereby reducing the requirement for increased power generation capabilities. To this end, the province, by way of the Independent Electricity System Operator (IESO), will be implementing a centralized Meter Data Management / Repository to aggregate utility data from the multiple AMI systems being implemented across Ontario. The IESO has created validation rules, and synchronization processes to control data and ensure that data is complete and suitable for billing.

It should be noted that CHEC members fully support this endeavour on behalf of the IESO and the province of Ontario, and that the interests of the RFP document are not related to those of the IESO and the centralized MDM/R. The Operational Data Storage requirements discussed herein are for the purpose of storing AMI Data being collected by CHEC's AMI systems, for which there is no provision in the centralized system to store and further utilize to implement operational efficiencies that will now become possible through the implementation of this new metering infrastructure.

1.3 CHEC's Approach to Smart Metering

With respect to the Provincial government's Smart Metering Initiative, CHEC has taken a collaborative approach to becoming educated on this mandate by working with other Ontario utilities and advocacy groups. CHEC hopes to evaluate Bidders as objectively as possible with the end goal of selecting the best-fit provider for an ODS, thereby allowing CHEC members to achieve their goals, as well as those of the provincial Smart Meter mandate.

Along with satisfying the provincial mandate of measuring "how much electricity a customer uses each hour of the day, and to use that data to charge customers an energy price that varies depending on when the electricity was consumed" (OEB Smart Meter Plan; January 26, 2005; page i); CHEC members will also implement the Smart Meter Network to improve overall efficiency within each members respective service territory.

CHEC would like to reiterate their support for the IESO MDM/R system that is being implemented, and that the utilities will look to the ODS to support their needs for the introduction of efficiencies that become possible through the use of Operational data that is available through the AMI system. Due to the possibility that the centralized system may one day accommodate these needs, and in keeping with the utility's desire to minimize duplication in utility infrastructure, combined with the relative infancy of Operational Data Storage systems, the utilities will procure a system that is established in the Application Service Provider (ASP) model, allowing the system to grow with the utility needs, but also provide flexibility with regards to term; in the event that the centralized system is able to accommodate the operational needs as well as billing requirements, the utilities would support (and move to) the IESO model.

1.4 Smart Meter Terminology

For the purposes of this procurement process, and within this Request for Proposal document, CHEC has opted to utilize the terminology as defined by the Ministry of Energy in their *Functional Specification for an Advanced Metering Infrastructure Version 2* (dated July 5, 2007), Section 3, *Definitions.* For reference, this document has been included herein as Appendix "A".

1.5 Other Terms

1) ***MDM/R:*** Within this document the acronym MDM/R has been used in reference to the centralized Meter Data Management / Repository that is owned and operated by the Independent Electricity System Operator (IESO). Currently the IESO is working to integrate Smart Meter Data from systems that were installed in Phase One of the Ontario Smart Meter Initiative.
2) ***ODS:*** Within this document the acronym ODS will be used in reference to the Operational Data Storage Services being sought in (potentially) a temporary capacity for the purposes of auditing and validating smart meter data until such time that the centralized repository is in place. At that time CHEC members will make a business decision whether or not to continue utilizing the ODS based on the functionality that is available in ODS compared to that currently in place with the MDM/R. For example, at this time it is not clear whether MDM/R will be used to store operational information. If CHEC members are able to implement efficiencies as a result of the operational data being received from the installed AMI systems, it may be in CHEC members' best interests to continue utilizing ODS.

3) ***Bidder*** shall refer to the vendor proposing a solution to this RFP document.
4) ***Vendor*** shall refer to the successful Bidder. The term Vendor will be used when stating future requirements, to be performed only by the successful Bidder.

1.6 Key Dates

Below is the expected timeline that CHEC will be following during the evaluation of available ODS solutions. CHEC reserves the right to adjust these dates as needed. All Bidders will be notified if any of the following dates are altered. As can be seen, it is the intention of CHEC members to make their decision by January 30, 2009.

Dates of Significance

RFP released by CHEC:	**November 14, 2008**
Bidder Response with Intention to Bid:	**November 21, 2008**
Final Questions Due:	**November 28, 2008**
Answers to Questions:	**December 5, 2008**
Closing Time (RFP Due):	**3:00pm EST December 12, 2008**
Vendor Presentations:	**January 5 - 9**
RFP Decision:	**January 30, 2009**

Section 2: Instruction to Bidders

2.1 Bid Documents

This Request for Proposals (RFP), establishes the system products and services that CHEC members wish to acquire. This bid document is the basis upon which CHEC seeks firm proposals from selected Bidders and upon which proposals will be evaluated. The documents are:

1) This RFP (a .pdf document), including Appendices that are integral to it.
2) CHEC_ODS_RFP_PricingFunctionality_Nov2008.xls, a Microsoft Excel workbook. This file allows for entry of pricing information, as well as confirmation of compliancy with the required regulations, and will heretofore be referred to as the Pricing Spreadsheet.

2.1.1 Pricing and Compliancy Spreadsheet

The Pricing spreadsheet will allow for the Bidder to enter their pricing information in a standard format, as well as allow the Bidder to attest to their product's functionality. As per Section 2.4 *Proposal Format Instructions*, any hard copies of the pricing submission should be submitted in a separate envelope, marked "PRICE OFFER".

The following tabs are included within the Pricing and Compliancy Spreadsheet:

1) ODS_Functionality: This tab requires completion by the Bidder, and will act as their product functionality statement providing detailed information on product capabilities.
2) Pricing_Option1_ASP: This tab requires completion by the Bidder
3) Pricing_Option2: This tab is optional. If the Bidder feels that a pricing format apart from that provided in the Pricing_Option1_ASP tab will better represent their product offering, they may complete the Option 2 tab. **NOTE: In the event that the bidder chooses to complete Pricing Option 2, the utilities will still require a completed Option 1 tab.**

2.2 Intention to Bid

Recipients of this RFP are asked to inform CHEC of their intention to bid by completing the template form found in Section 2.19 *Proposal Forms*, and by submitting this form by the date shown in Section 1.6 *Key Dates*. Recipients that express intention to bid will be included in all correspondence (if any) during the bidding process. Please provide full contact information and expression of intention via the provided form to the CHEC member contact as per instruction in Section 2.19.1 *Intention to Bid Form*.

2.3 Submission Requirements

1) A complete proposal will consist of an original and seven (7) copies of each of
   a) The proposal forms,
   b) The Bidder's Response document (including all associated attachments),
   c) Pricing spreadsheet: CHEC_ODS_RFP_PricingFunctionality_Nov2008.xls; a Microsoft Excel workbook,
   d) Accompanying the Bidder's Response document should be the proposal forms provided in Section 2.19 *Proposal Forms*,
   e) The required format of the Bidder's Response document is outlined in Section 2.4 *Proposal Format Instructions*,
   f) The Pricing and Compliancy spreadsheet will allow for the Bidder to enter their pricing information in a standard format, as well as allow the Bidder to attest to their product's functionality,
   g) A soft copy of all of the above forms and documents should also be provided on one CD.

2) The original hard copy shall be clearly identified as "ORIGINAL"; the remainder (i.e. seven copies) shall be marked as "COPY". In the event of discrepancy between the copies of the Response, the one marked "ORIGINAL" shall prevail. Each Bidder's Response shall consist of the required documents with the required number of copies of all commercial information, including pricing, terms and conditions and exceptions (if applicable). Faxed or late proposals will not be accepted. Proposals must be sealed and marked clearly quoting the proposal number referred to on the cover sheet of the proposal documents. The use of any means of delivery of a proposal shall be at the risk of the Bidder.
3) Any Bidder wishing to provide additional information other than what is requested in the proposal documents must place such additional information in a separate section marked Supplementary Information, as per Section 2.4 *Proposal Format Instructions*. Any Additional Information or any unsolicited value-added alternatives may, in CHEC's absolute discretion, be given due consideration, or not.
4) CHEC member utilities shall not be liable for, nor shall they reimburse any Bidder for costs incurred in the preparation of proposals, or any other services or samples that may be requested as part of the evaluation process.
5) The Proposal Forms shall be signed under the Corporate Seal of the Bidder, by the duly authorized signing officer(s). All submitted pages shall be initialled by such officer(s).

2.4 Proposal Format Instructions

Where information has been requested through this RFP, the Bidder's Response should clearly indicate the RFP section number that the Response pertains to. The Bidder's Response should be organized according to the following sections:

1) Section 1 of the proposal will contain the Bidder's Executive Summary, no more than two pages in length that introduces the Bidder and highlights key features of the proposal.
2) Section 2 of the Proposal **should be provided in a separate envelope which has been clearly marked "PRICE OFFER".** This section will contain the summary pages pertaining to the Price Offer, contained within the Pricing and Compliancy Spreadsheet. The Bidder's detailed itemized pricing information for all goods or services is to be contained within the Pricing Spreadsheet which is to be included with the Response in its entirety as well as within this section. Any alternative pricing offers may also be included within the Pricing Spreadsheet, by adding tabs as needed. All pricing shall be expressed in Canadian currency, exclusive of taxes. If your originating currency is not Canadian, the currency exchange that was used to calculate the price in Canadian currency is to be provided.
3) Section 3 of the proposal will contain the functionality statement that is included within the Pricing Spreadsheet as the following tab: ODS_Functionality.
4) Section 4 of the proposal will contain all requested information regarding the Bidder (CHEC RFP Section 4: *Bidder Company Information*) in the order presented in this document, with the numbering used in this document.
5) Section 5 of the Bidder's proposal will contain the requirements of Section 5 of this RFP Document (Section 5: *ODS Solution Technical Requirements*), in the order presented in this document, with the numbering used in this document.
6) Section 6 of the Bidder's proposal will contain any additional documentation that the Bidder decides to provide regarding their offering.

2.4.1 Proposal Format Example: Section 5

Within Section 5: *ODS Solution Technical Requirements* of the RFP, an indicator has been included with the subsection heading to indicate the requirement of the Bidder to provide information pertaining to the functionality of their product (with regards to the section requirements), or a statement of compliancy AND information pertaining to the functionality of their product with respect to the requirement of the section.

(I) When an (I) has been included with the section heading, CHEC members require Information regarding the proposed system's functionality, and the methodology utilized to satisfy the RFP requirement.

(C) When a (C) has been included with the section heading, CHEC members require a statement of compliancy from the Bidder. Within the Submission documentation, the Bidder is required to state the proposed product's compliancy with the requirement by stating Fully Compliant, Partially Compliant, or Not Compliant. In instances where the product is Partially Compliant, or Not Compliant, the Bidder is required to state their plans (complete with development time line) to bring their product into compliancy.

(CI) When a (CI) has been included with the section heading, CHEC members require both a statement of compliancy, and Information regarding the proposed system's functionality, and the methodology utilized to accommodate the RFP requirement.

The method with which the Bidder provides information and compliancy statements is detailed within the individual sections, as well as within the Pricing and Compliancy Spreadsheet.

SAMPLES of response for Section 5: *ODS Solution Technical Requirements*, demonstrating that the section numbering from this document is to be retained, and that each section should be included, and shall include within it a statement of compliance (which is also included in spreadsheet form in the Pricing and Functionality Spreadsheet).

5.5.6 Reporting: Custom Queries (C)

The ODS will be capable of executing custom queries to accommodate any areas where standard reports are not available.

Vendor's declaration of compliance: **Fully Compliant**

5.9 Scalability (CI)

The Bidder must describe its proposed ODS data model demonstrating the model's flexibility and scalability to deliver cumulative and interval metering over the next ten years. The system should be designed for a minimum of 250,000 customers, assuming 2 years of online interval data and 7 years off-line data storage. Please specify the methodology for data storage and retrieval.

Vendor's declaration of compliance: **Fully Compliant**

Vendor's Functionality Statement: The ODS system being proposed has been implemented in several deployments (in other markets) of 300,000+ meters, with the largest deployment being 500,000 meters. In addition to these live deployments, the system has been volume tested to more than 1.5 million meters. While these large deployments are all electric AMI deployments, we have deployed the system in some smaller cooperatives 80,000+ meters which are multi-commodity (electric, water, and gas). We believe that together, these experiences demonstrate the scalability required to be successful in the Ontario marketplace. References have been included which can speak to these experiences.

2.5 Adjustments / Substitutions

1) A proposal may be altered by a Bidder only by submitting another proposal at any time up to the Closing Time. Adjustments by telephone, facsimile, telegram or letter to a proposal already submitted will not be considered. The last proposal received by CHEC's designee shall supersede and invalidate all proposals previously submitted by the Bidder for this RFP.
2) During the period prior to the Closing Time, changes made by CHEC members to the proposal documents will be issued by CHEC to the Bidders as written addenda. The Bidder shall list in its proposal all addenda that were considered in the preparation of its proposal.
3) No substitutions or deviation from the Specifications, Proposal Form or General Conditions of Contract will be permitted without CHEC's approval in writing.

2.6 Complete Bid

Bidders are requested to submit bids that are complete and unambiguous without the need for additional explanation or information. CHEC members reserve the right to make a final determination as to whether a bid is acceptable or unacceptable solely on the basis of the bid as submitted, and proceed with bid evaluation (or not) without requesting further information from any Bidder. If CHEC members deem it desirable and in their best interest, CHEC may, in its sole discretion, request from any Bidder or Bidders additional information clarifying or supplementing any submitted bid.

2.7 Clarifications

Upon the issuance of this RFP to Bidders, and continuing through the submission date, all questions or other communications with CHEC shall be by email only:

chec@util-assist.com

CHEC members will respond to the question in writing, with both the question and response provided to each Bidder that has declared intention to bid. No response will be made to questions submitted after November 28, 2008.

2.8 Grounds for Disqualification

It is a requirement of this RFP document that Bidder's submitting proposals for evaluation complete the Pricing Spreadsheet including the ODS_Functionality tab and format their bid submission according to Section 2.4 *Proposal Format Instructions*. CHEC reserves the right to reject any incomplete bids (as per Section 2.6 *Complete Bid*).

NOTE: Where functionality (within the ODS_Functionality tab of the Pricing Spreadsheet) has been misrepresented, CHEC reserves the right to disqualify the Bidder from further evaluation of the RFP.

2.9 Post Bid Meeting

CHEC members reserve the right to invite any or all Bidders to make an in-person presentation regarding the proposed ODS solution. CHEC may request Bidder's assistance in arranging visits to other installations where Bidder has deployed the solution.

2.10 Withdrawal of Proposal

Bidders will be permitted to withdraw their proposal unopened after it has been submitted if such a request is received by the designee of CHEC in writing, prior to the Closing Time.

2.11 Bid Inconsistencies

Any provisions in Bidder's proposal that is inconsistent with the provisions of this Request for Proposals, unless expressly described in the proposal as being exceptions, are deemed waived by the Bidder. In the event the order is awarded to Bidder, any claim of inconsistency between the proposal and this RFP will be resolved in favour of this RFP unless otherwise agreed to in writing by CHEC.

2.12 Bidder's Statement of Understanding

By submitting a response to this RFP, Bidders acknowledge the following:

1) The Bidder acknowledges that it has carefully examined, understands and accepts the proposal documents, has carefully examined the requirements contained in the proposal documents and hereby submits an offer according to the requirements set forth in this proposal.
2) It is understood that this proposal, if it has not been withdrawn in accordance with Section 2, subsection 2.10 *Withdrawal of Proposal*, is irrevocable and shall remain open for acceptance by CHEC for a period of ninety (90) working days following the opening of the proposals.
3) It is further understood by the Bidder that if CHEC accepts its proposal, then the Bidder is bound by the Contract and agrees to provide the goods and/or services upon the terms and conditions of the Contract
4) The Bidder acknowledges and agrees that all quantities shown in the proposal documents are approximate only. Quantities may be subject to increase, decrease, or total deletion in the event that CHEC determines in its absolute discretion that such change is required.
5) While CHEC has used considerable efforts to ensure an accurate representation of information in this Request for Proposal, the information contained in this Request for Proposal is supplied solely as a guideline for Bidders. The information is not guaranteed or warranted to be accurate by CHEC, nor is it necessarily comprehensive or exhaustive. Nothing in this Request for Proposal is intended to relieve Bidders from forming their own opinions and conclusions with respect to the matters addressed in this Request for Proposal.

2.13 Proposal Evaluation

1) All proposals shall be opened after the Closing Time in the presence of CHEC's Representative or another individual designated to open the proposals by CHEC. The opening will not be public.
2) In determining the contract award, the lowest proposal will not necessarily be accepted, and CHEC reserves the right to accept or reject any or all proposals in its absolute discretion. Further, proposals may be accepted or rejected in total or in part.
3) The Evaluation Committee will review proposals and will then carry out interviews with selected Bidders for clarification as required.
4) It is anticipated that a written contract will be negotiated immediately after the successful Bidder has been notified. If a contract cannot be negotiated within thirty (30) days of notification, CHEC may, at its sole discretion at any time thereafter, terminate negotiations with that Bidder and either negotiate a contract with the next qualified Bidder or choose to terminate the Request for Proposal process and not enter into a contract with any of the Bidders.

2.14 Award of Contract

1) The Bidder acknowledges that CHEC reserves the right, privilege, entitlement and absolute discretion, and for any reason whatsoever to:
   a) Cancel this Request for Proposals at any time, either before or after the Closing Time;
   b) Accept a proposal which is not the highest scoring proposal submission, or reject a proposal that is the highest scoring proposal even if it is the only proposal received;
   c) Accept the proposal deemed most favourable to the interests of CHEC or that may provide the greatest value advantage and benefit to CHEC based upon but not limited to price, ability, quality of work, service, past experience, past performance and qualification;
   d) Accept or reject any and all proposals, whether in whole or in part;
   e) Award any part of any proposal; or
   f) Accept or reject any unbalanced, irregular, or informal proposals.
2) The Bidder acknowledges that CHEC will evaluate proposals using an internal scoring method as referenced in section 2.13 *Proposal Evaluation* and other criteria which CHEC deems relevant, even though such criteria may not have been disclosed to the Bidder. By submitting a proposal, the Bidder acknowledges CHEC's rights under this section and absolutely waives any right, or cause of action against CHEC and its consultants, by reason of CHEC's failure to accept the proposal submitted by the Bidder, whether such right or cause of action arises in contract, negligence, or otherwise.
3) Contract award, if any, will be communicated by written notification from CHEC to the successful Bidder. The successful Bidder, if any, in the presence of the designate, must sign the Contract Agreement in triplicate (3), within seven (7) Working Days of written notification of acceptance.
4) Bidders whose proposals have been rejected by CHEC will be notified within thirty (30) days of the award date.
5) The successful Bidder shall provide CHEC with a designated inside customer service representative. Any disputes and/or queries with respect to the Contract will be directed to the CHEC representative, whose decisions with respect to any matter under dispute shall be final and binding.

2.15 Freedom of Information

Proposals submitted to CHEC become the property of CHEC and, as such, are subject to the *Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, c. F.31, as amended.

2.16 Ownership of Data

CHEC shall own all data collected by the AMI system, and subsequently stored by the ODS. Data collected and stored by the system shall not be used for any purpose without the approval of CHEC.

2.17 Proposal Evaluation Criteria

CHEC will evaluate proposals using an internal scoring method that weights various parameters to give the CHEC Smart Meter Team insight into the strengths of each proposal relative to CHEC's needs. CHEC's internal scoring method values the following proposal attributes (order of presentation does not reflect priority):

Figure 1 Proposal Evaluation Criteria

Proposal Evaluation Criteria	Section	% Total Points
Project Overview	**3**	
Bidder Information	**4**	
ODS Functionality	**5**	
General Data Management Requirements		
Performance Service Levels		
System Integration		
Meter Event Manager		
System Disaster Recovery Planning		
ODS System Reporting		
Scalability		
ODS System Security		
Perspectives expressed by reference utilities		
Section 3 through 5 inclusive:		**60%**
Pricing Weighting:		**40%**
Total		**100%**

Along with the Bidder's company information, and statements of understanding regarding the project, the answers to sections 3 through 5 will represent 60% of the total weighting of the RFP. Pricing submitted will represent 40% of the total weighting of the RFP. Bidders will be selected for further discussion based on the Team's judgment, developed using the scoring method. CHEC reserves the rights to alter its internal scoring method and to exercise whatever judgment it deems in the best interests of CHEC in selecting an ODS solution provider.

2.18 Payment

When the Vendor has completed all work in accordance with the terms of the contract documents, the Vendor shall submit to CHEC a request for final payment. The request for final payment shall constitute a waiver of all claims by the Vendor except for claims specifically listed in the request. CHEC will make payment within forty-five (45) days of receipt of a request for payment.

Vendor's submission of its request for final payment shall constitute its warrant that the Vendor has to the best of its knowledge fully completed all work included in the Contract and has fully paid for labour, materials, equipment, services, taxes and all other costs and expenses resulting from this Contract.

2.19 Proposal Forms

Within this section, there are two forms required for submission. The first form is found in Section 2.19.1 *Intention to Bid Form*; the intention of this form is to allow the vendor to provide a standard email Response to CHEC designee to notify CHEC of the Bidder's intent to respond to the RFP.

2.19.1 Intention to Bid Form

The procedure to be utilized for this form is to copy and paste the following content into an email, and send the email to:

chec@util-assist.com

according to the time line as established by Section 1.6 *Key Dates*.

INTENTION TO BID NOTIFICATION FORM

PROPOSAL NO. 2008-1114

Intention to Bid:
Please allow this email to represent "__Insert Company Name Here__" intention to respond to RFP 2008-1114.

Contact for communication regarding bid: ________________________________
Contact phone number: ________________________________
Contact email address: ________________________________

We acknowledge the requirement for our ODS solution to, at minimum, audit the performance of the installed AMI to assist CHEC in making certain the AMI meets the Ministry of Energy's minimum functional requirements as outlined in the document *Functional Specification For An Advanced Metering Infrastructure Version 2* (dated July 5, 2007). Our proposal will include the required compliance statements and documents to properly express our ability to meet these requirements. We also acknowledge the Submission Deadline is 3:00 PM Eastern Time on December 12, 2008.

2.19.2 RFP Submission Form

The procedure to be utilized for this form is to print the following pages to be included with the RFP submission, which should be addressed to:

Attn: Ms. Ruth Tyrell
CHEC Group
c/o Orangeville Hydro
400 C Line
Orangeville, ON L9W 2Z7

according to the time line as established by Section 1.6 *Key Dates*.

Cornerstone Hydro Electric Concepts

Proposal Number: **RFP 2008-1114**

FOR: OPERATIONAL DATA STORAGE SYSTEM & SERVICES

THIS PROPOSAL IS SUBMITTED BY:____________________

ADDRESS:

TELEPHONE: FAX NO.:

BIDDER G.S.T. No.:

PERSON(S) SIGNING ON BEHALF:____________________________(print)

POSITION(S) OF THE PERSON(S):__________________________________(print)

To CHEC, Hereafter called "Owner":

I/WE ____________________________________ the undersigned declare:

1. THAT no Person(s), Firm or Corporation other than the one whose signature(s) of whose proper officers and the seal is or are attached below has any interest in this proposal or in the contract proposed to be taken.

2. THAT this proposal is made without any connections, knowledge, comparison of figures or arrangements with any other company, firm or person making a proposal for the same work and is in all respects fair and without collusion or fraud.

   THE Bidder insures that no Owner and or employee of Owner, is, or has become interested, directly or indirectly, as a contracting party, partner, stockholder, surety or otherwise howsoever in or on the performance of the said contract, or in the supplies, work or business in connection with the said contract, or in any portion of the profits thereof, or of any supplies to be used therein, or in any monies to be derived there-from.

3. THAT the several matters stated in the said proposal are in all respects true.

4. THAT I/WE have carefully examined the requirement(s), as well as all the Instructions to Bidders, Project Overview, ODS Technology – Technical Requirements, proposal Forms, and Appendices relating thereto, prepared, submitted and rendered available by the Owner and hereby acknowledge the same to be part and parcel of any contract to be let for the work therein described or defined.

5. THAT I/WE do hereby propose and offer to enter into a contract to deliver all work as described or implied therein including in every case freight, duty, exchange, G.S.T. and P.S.T. in effect on the date of the acceptance of proposal, and all other charges on the provisions therein set forth and to accept in full payment therefore, the sums calculated in accordance with the actual measured quantities and unit prices set forth in the proposal herein.

6. THAT Addendum/Addenda No. ___ to ___ inclusive relate to the said contract and Bidder hereby accepts and agrees to the same as forming part and parcel of the said contract.

7. THAT additions or alterations to or deductions from the said contract, if any, shall be made in accordance with the prices stated in the Schedule of Items of Unit Prices in strict conformity with the requirements of the Contract.

8. THAT this offer is irrevocable and open to acceptance until the formal contract is executed by the awarded Bidder for the said requirement(s) or Sixty (60) working days, and unit prices for as long as stated elsewhere in the document, whichever event first occurs and that the Owner may at any time within that period without notice, accept this proposal whether any other proposal has been previously accepted or not.

9. THAT the awarding of the contract, by the Owner is based on this submission which shall be an acceptance of this proposal.

10. THAT I/WE also understand that the Owner reserves the right to accept or reject all or part of this proposal or any other and also reserves the right to accept other than the lowest proposal.

The undersigned affirms that he/she is duly authorized to execute this proposal.

BIDDER'S SIGNATURE AND SEAL:

NAME: ______________________ ______________________
(Please Print) (Signature)

POSITION: ______________________

WITNESS
NAME: ______________________ ______________________
(Please Print) (Signature)

POSITION: ______________________

(If Corporate Seal is not available, documentation should be witnessed)

DATED AT THE ______________________ THIS ________
(City/Town) (Day)

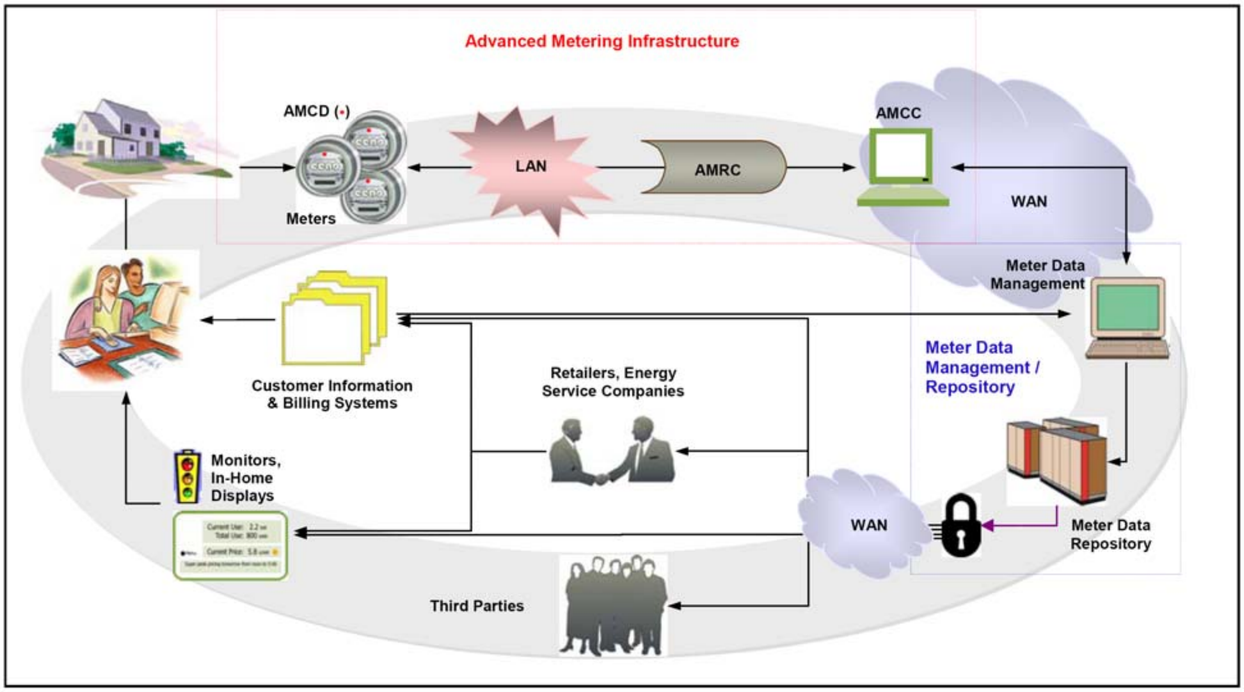
DAY OF ______________________ 2008.
(Month)

Section 3: Project Overview

3.1 Smart Metering Infrastructure – AMI Landscape

The Advanced Metering Infrastructure (AMI) which CHEC is installing is meant to satisfy the requirements of the provincial Smart Meter Initiative (SMI), which is hoped to contribute to the creation of a conservation culture in Ontario. The metering and associated infrastructure (i.e. AMCDs, AMRCs, and AMCC) will be owned and operated by CHEC, and the centralized Meter Data Management/Repository (MDM/R) will be owned and operated by the Independent Electricity System Operator (IESO). There are performance requirements detailing success rates for data collection from the AMI infrastructure, and time requirements within which the data must be provided to the centralized MDM/R. Following is a diagram depicting the data flow for the Ontario Smart Meter landscape.

Figure 2: Ontario Smart Metering System Data Flow



Performance requirements for the AMI have been specified within the Ministry of Energy document entitled *Functional Specification for an Advanced Metering Infrastructure Version 2* (dated July 5, 2007), which has been provided for reference as Appendix "A". As discussed within this document the AMI system includes the Advanced Metering Communication Devices (AMCD), the Local Area Network (LAN), Advanced Metering Regional Collector (AMRC), the AMI Wide Area Network (AMI WAN) and an Advanced Metering Control Computer (AMCC). The system will provide the infrastructure within which date and time stamped hourly meter reads are remotely collected and transmitted daily to CHEC's AMCC, and which will eventually be sent to the centralized Meter Data Repository (MDM/R) through the MDM/R Wide Area Network (MDM/R WAN).

The MDM/R functions include collecting and storing data, processing it for TOU and CPP billing, and making it accessible to consumers and to LDC's in accordance with their billing cycles. The data will also be made available to retailers, energy service companies and other interested parties in a manner that protects the privacy of consumers.

As discussed in Section 1.3 *CHEC's Approach to Smart Metering*, CHEC members are currently engaged in a project to install Smart Metering in all residential and commercial locations by December 2010. Presently CHEC has a total of over 110,000 residential and commercial customers, with smart meter installation commencing 2009.

Planning for the Commercial and Industrial component of the smart meter initiative is currently being developed and is not part of the current deployment. However, Bidders are welcome to provide comments on their ODS offering for Commercial/Industrial data, and budgetary pricing may be provided separately should the Bidder decide to do so. Desirable Commercial and Industrial analytical tools have been described in Section 5.4 *Commercial and Industrial Data,* and the Bidder's information regarding these functionality components can be provided as per the Section format instructions included in Section 2.4 *Proposal Format Instructions*, however Bidders are to understand that the immediate requirements of CHEC are for a residential ODS solution to audit the performance of the AMI. The intent of the ODS is NOT to replicate any functions currently in place within the centralized MDM/R. CHEC looks to the ODS to facilitate the implementation of operational efficiencies (currently the centralized MDM/R does not accept operational metering data).

3.2 CHEC's Operational Data Storage Requirements

Section 3.1 *Smart Metering Infrastructure – AMI Landscape* outlines the requirements placed on CHEC in order to meet the provincial mandate.

The Operational Data Storage requirements being procured through this RFP document are considered (at this time) to be exclusive of the requirements being placed upon the IESO centralized MDM/R. The solution that is of interest to CHEC through this process will be utilized to audit the performance of the AMI infrastructure currently being installed, and to store operational data that may be of future use to CHEC. It is CHEC's understanding that these functionality components are standard to ODS solutions, and may not form part of the MDM/R functionality. CHEC would like to clearly express that their intention is NOT to duplicate infrastructure being implemented by provincial entities, but rather to ensure that the AMI infrastructure being deployed by CHEC will satisfy the needs of the Ontario Energy Board (i.e. the Regulator).

3.3 CHEC's Smart Metering Initiative: Current Environment

3.3.1 Description of Environment

For reference, we have also included the following information pertaining the CHEC's back office systems.

UTILITY	CIS:	Meters	Projected AMI Install:
Centre Wellington Hydro Ltd.	Harris Northstar	4,500	August 10, 2009
COLLUS Power Corp.	Harris Northstar	11,500	June 22, 2009
Innisfil Hydro	Harris	12,000	March 16, 2009
Lakefront Utilities Inc.	Harris	7,000	February 2, 2009
Lakeland Power Distribution Ltd.	Harris Northstar	7,000	April 6, 2009
Midland Power Utility Corporation	Harris v5.2.19	5,000	June 15, 2009
Orangeville / Grand Valley	Advanced	8,000	September 21, 2009
Orillia Power Distribution Corporation	Harris v5.2.19	9,000	March 2, 2009
Parry Sound Power Corporation	Harris v5.2.19	2,500	March 2, 2009
Rideau St. Lawrence Distribution Ltd.	Harris	4,500	April 27, 2009
Wasaga Distribution Inc.	Advanced	9,500	October 5, 2009
Wellington North Power Inc.	Harris Northstar	2,500	June 29, 2009
Westario Power Inc.	SAP	14,500	February 2, 2009

3.3.2 AMI Service Level Agreement

The AMI network has been deployed in such a manner as to accommodate the following performance levels:

i. Percent of hourly (interval) readings captured: 98% in 24 hours
ii. Percent of daily (register) readings captured: 98% in 24 hours
iii. In addition to the above requirements, 99% of all readings (99% of register, and 99% of interval) are required in 72 hours (rolling statistic), and 99.5% of all readings (99.5% of register, and 99.5% of interval) are required in 30 days (calendar statistic). These requirements will demonstrate the Bidder's ability to acquire the readings that were missed in 24 hours, over the subsequent time periods (i.e. continued commitment to acquire as many readings as possible).
iv. Percent of meters communicated within 24 hours: 99.9% (while it is conceded that some meters may be difficult to communicate with, and therefore acquire 100% of the readings 100% of the time, the aim of this statistic is to show that 99.9% of meters can be reached on a daily basis).

This information has been provided as one of the critical functions of the ODS will be to audit the performance of the AMI to ensure that these Service Levels are being satisfied.

3.4 Scope of Work

CHEC, through this RFP, is seeking a cooperative and mutually beneficial relationship with a ODS provider which will allow CHEC to successfully fulfill their regulatory requirements for data collection. That is, it is anticipated that the ODS services being procured will enable CHEC to ensure the performance requirements as documented in Section 3.3.2 *AMI Service Level Agreement* are being satisfied. Knowledge of AMI performance statistics will provide CHEC with the knowledge that sufficient AMI infrastructure has been deployed (or not), such that the performance expectations can be met.

Additionally, AMI systems provide data which can enable CHEC to implement operational enhancements for their customer base. Given that the AMI deployment is in its infancy, CHEC is not in a position to make use of all of the data that is acquired through the system at this time. However, it is CHEC's goal to establish the ODS system such that this information can be stored now, and utilized at a later time.

It is CHEC's intention to implement commercial and industrial applications as appropriate in the future. Planning for this application is ongoing, and no timelines for implementation are available at this time. Therefore, this request for proposal for ODS solutions will address CHEC's requirements for smart metering in residential applications only. However, Bidders should be aware that commercial and industrial applications will be installed in the future, and if the Bidder also provides a solution for commercial and industrial applications, the response may also address this solution distinctly segregated from the solution provided for residential application, if possible. If the proposed solution is applicable for commercial and industrial customers with no modifications, the Bidder shall identify such.

As stated within Section 1.3 *CHEC's Approach to Smart Metering*, it is the intent to procure the ODS solution in an ASP model to mitigate the risk associated with purchasing a license for software which may become redundant due to the ongoing development of the centralized MDM/R. CHEC supports the work of the IESO, and the use of the centralized system, and look to use the ODS to facilitate the introduction of Operational Efficiencies during the period in which these functions are unavailable through the centralized system.

CHEC considers the following list of services as required to successfully satisfy the intent of this RFP:

- Project management, system design, commissioning and training
- System security (i.e. detailed security parameters to protect all information collected)
- Service levels and value added services
- Applicable costs, pricing and rates
- Provide the technical expertise required to establish communications between the AMCC and CHEC's back office systems
- Establish an understanding of the demarcation point
- Describe the technology roadmap for the proposed system/technology

Section 4: Bidder Company Information

4.1 Financial / Business Stability

1) What is the current size (number of employees), turnover rates for last three (3) years, and location(s) of the Bidder's company?
2) Number of employees assigned to application development and support.
3) What is the current financial condition of the Bidder's company? Provide supporting documentation and annual reports for the last three years. If the company is privately held, supply sufficient information to document the company's financial status.

4.2 Experience providing same or similar products & services

1) How many years has the Bidder been in business?
2) How long has the Bidder been providing ODS solutions?
3) How long has the proposed solution been deployed and implemented in the field excluding any period of time for which it was in a Beta Test status?
4) Describe the Bidder's primary line of business and the percentage of its business derived from the sale of ODS solutions and associated services.
5) Bidders should identify and describe services they could offer CHEC as part of the Contract that would support environmentally responsible business practices.
6) Bidders are to provide data to support their safety record such as corporate safety statistics, internal safety record, WSIB rating, injury rate or injury severity. In addition, Bidders must provide documentation supporting their commitment to safety within their facilities and design of products.

4.3 Contract Manager

The Bidder is asked to acknowledge the requirement to designate a Contract Manager, who shall have the authority to handle and resolve any technical issues, disputes or contractual issues in a timely manner. The Bidder should describe the Contract Manager's experience with managing projects of a similar size and scope, including timelines, and results if applicable. Response should include the Contract Manager's and any other related team member's Curriculum Vitae (CV).

4.4 Perspectives expressed by references

To ensure long-term viability and maintenance of the system, the selected Bidder must be a proven vendor in the area of application software and therefore the following information is requested:

1) Provide a list of at least three (3) references (contact names and phone numbers) for companies using the Bidder's proposed system to perform the same or similar application(s) as the one(s) described in this RFP for the past three (3) years.

Section 5: ODS Solution Technical Requirements

5.1 General Data Management Requirements (I)

CHEC is seeking an AMI specific ODS that is designed to store meter data and provide isolation of business processes and business systems from the details of metering and meter data collection, in a multi-vendor, multi-technology environment.

Any ODS proposed by the Bidder shall allow for the application of consistent processes and the maintenance of consistent interfaces independent of how, when, or where various meter reading technologies are deployed. This is intended to simplify and significantly reduce the likelihood of errors in business processes that utilize meter data. It should also allow for the most cost-effective AMI meter reading technologies to be deployed, without affecting downstream processes.

Bidder is to propose a fully capable ODS system able to manage the ongoing collection of all cumulative and interval meters for electricity, and potentially water and gas, as required by CHEC's current structure and operational responsibilities.

The ODS shall utilize a relational and fully versioned database that provides for long-term data storage of register, interval, tamper, outage, and meter event data. The system will provide for business process integration, and be accessible by all business and analytical systems, and readable by users of meter data throughout the utility. The ODS should have the ability to collect energy data streams from physical metered channels, endpoints, or modules, or calculate it as needed. The data should be linked together in flexible relationships that are managed over time.

The ODS data model should provide isolation of users from the day-to-day details of meter reading data collection processing. However, the ODS shall still provide access to those details for the systems and users that require it.

5.2 System Integration (I)

Systems of interest with regards to system integration include CIS systems, Outage Management Systems (OMS), and AMI and other meter reading data collection systems. Bidders are asked to provide a listing of these systems which can currently integrate with the proposed solution. While these systems are of immediate interest, it is expected that CHEC members will investigate the integration of GIS, WFM systems, WEB presentment OMS and other utility data systems in the future. Bidders are invited to provide any information they deem relevant to these interests.

5.2.1 Interaction with AMI (CI)

The ODS solution shall provide the following functionality with regards to the handling of data as provided by the AMI infrastructure:

i. AMI data insertion into the ODS will be dynamic.
ii. The system will store data in the original time increments as provided by the AMI system (ie. RAW AMI data including missing intervals and bad data).
iii. The system will store validated register and interval data in any time increment (ie. Intervals of 1 minute, 2 minute, 5 minute, 15 minute, etc.).
iv. Data storage will be energy independent and the ODS will be capable of storing and processing readings from all registers of all AMI endpoints (endpoints can include electric, water, and gas meters, with all available data from each meter).

v. Hourly reads in the system must retain the precision of the meter, to a minimum precision of 10 Watt hours (.01 kWh) for each residential electric data register (interval or otherwise). Bidder is requested to also provide detail regarding the precision of data storage for Commercial/Industrial metering (i.e. It is expected that the ODS would retain the precision of the meter regardless of the number of decimal points.)
vi. The system will accommodate "Request and Response" brokering to/from multiple AMI systems.

Bidders are required, as per Section 2.8 *Grounds for Disqualification* to provide written acknowledgement of the requirement for the proposed solution to be currently capable of these functions for the Sensus AMI system.

5.2.2 Other Meter Reading Data Collection Systems (I)

In addition to the acquisition of Data from the AMI, the ODS shall handle meter data from multiple sources, such as handheld, mobile, fixed network, etc. The ODS will allow the integration of multiple advanced meter reading technologies from multiple suppliers. CHEC will require the ability to seamlessly deploy multiple technologies in conjunction with traditional meter reading methods, and the ability to merge modern and traditional meter reading methods and technologies without impacting or modifying downstream billing processes. This ability is considered of value given that CHEC continues to manually collect meter read data while they deploy their AMI network.

The ODS solution shall have the functionality to emulate and manage schedules, cycles, and routes of manual meter reading operations to allow transition of legacy meter reading tasks, including the functionality to:

i. Process cycle/route-based meter reading systems, such as handheld (i.e. Itron MV-RS) or automated meter reading technology (i.e. Itron ERT enabled electromechanical meters),
ii. Process non-cycle/route-based meter reading systems, such as two-way remote reading technologies (i.e. MV-90 interval data collection from POTS enabled communication modules),
iii. Manage schedules such that the ODS will request all of the meter reading required for a given billing (readings may actually be obtained from multiple systems and/or technologies),
iv. Maintain information about which system is used to obtain readings for each meter so that a given request can be broken into individual requests for each meter reading system,
v. Functionality to create partial or full routes when returning readings to the billing system and combine multiple commodities, i.e. water and gas, into a single meter reading route for field collection and return data to the ODS system.
vi. The ODS should maintain performance statistics for each meter reading system and for the system as a whole.

Given that the ODS can perform the functions listed above, in an effort to retain consistency in the presentation of data, CHEC requires that: time references in data presented must be based on the local time zone and use Daylight Savings Time. Any data that is presented that is not validated should be clearly indicated as such. For further validation requirements, see Section 5.3 *Validation, Editing and Estimation (VEE)*.

5.2.3 Customer Information System (CI)

The system should accommodate "Request and Response" Brokering To/From Multiple Customer Information Systems (CIS). Some of the CIS systems commonly utilized in the Ontario market include:

- Advanced
- Cayenta

- Daffron
- Harris NorthStar
- Harris 5.2.19.x
- HTE
- Peoplesoft
- SAP
- SPL

Bidders are requested to specify the CIS systems for which an interface currently exists, and whether there is a cost to implementing the interface that will be required for CHEC member's CIS systems. In the event that the ODS cannot interface with the CIS systems being used by CHEC (reference Section 3.3.1 *Description of Environment*), the Bidder is asked to provide a high level overview of their system's ease of customization.

As part of the synchronization that is required between ODS and CIS, it is expected that the proposed solution will allow for new or changed customer, account, site ID, and service point information, and that this information will be imported from the external Customer Information System (CIS) en masse or upon completion of service orders.

CHEC anticipates using the ODS to test the IESO Billing Request file format that will be utilized by the centralized MDM/R. If Bidders have experience in this regard, documentation should be included in the response.

5.2.3.1 Wholesale Settlement Calculations (I)

CHEC is interested in whether the system is capable of performing Wholesale Settlement Calculations with billing output files for CIS. If this option is not currently available, please detail the development path.

5.2.3.2 Export Capabilities (I)

In addition to the interface required to directly integrate CIS data, CHEC is interested in the proposed solution's ability to export data in XML format, and the Itron MVRS handheld format. Bidders are requested to provide information explaining their current functionality in this regard, as well as any associated costs to accommodate these requirements if they are not currently available. If incremental costs are not stated, it is CHEC's assumption that costs for this functionality is included in the system pricing (i.e. functionality is considered standard).

5.2.4 Outage Management System (CI)

It is expected that the proposed solution will allow for receipt and display of outage related events from the AMI. CHEC is interested in having these capabilities performed by the ODS system, thereby allowing improved restoration and other outage related services. With the information available from AMI it is expected that the dispatching process for field service crews will be streamlined.

Bidders are requested to provide a listing of interfaces available to integrate the proposed ODS with CHEC's OMS (reference Section 3.3.1 *Description of Environment*). If an interface is not currently available, Bidders should specify the estimated costs associated with the creation of the required interface. In addition to a list of interfaces, Bidders are asked to provide some details regarding past implementations and a list of references with regards to the integration of OMS.

5.2.5 Work Force Management (WFM) (I)

CHEC expects that initially all data will be imported from CIS. However, as the deployment of AMI continues, CHEC will require that the system allow new or changed data to be imported from the workforce management system at the completion of meter-related service orders. The system will allow configuration data to be synchronized on a daily basis using batch files, and should allow real-time transactions to be performed with web-based APIs. The ODS system should also have the ability to interface to the WFM system and automatically create service orders in events where a field visit is required.

5.2.6 3rd Party Interfaces (I)

The ODS must provide a robust, industry standard means for extracting data so that the data can be presented to other 3rd party applications. In addition to CIS, OMS, WFM, other 3rd party applications might include GIS, WEB products, Theft Analysis tools, Load Forecasting/Profiling tools, etc. Bidders are requested to provide detailed information regarding their experience integrating to 3rd party applications.

The system should contain Application Program Interfaces (APIs) for third party applications. The system should not have a load limitation to API's (multi-threaded). If there is a load limitation to API's, please indicate what the limitation is.

The ODS solution should contain the flexibility and functionality to load, change, correct, and view configuration data through use of the following tools:

i. Service Oriented Architecture (SOA) Bus;
ii. XML configurable import APIs (batch or real time);
iii. XML configurable export APIs (batch or real time);
iv. comma delimited file (CSV) exports (batch)
v. configuration attributes reports.

5.3 Validation, Editing and Estimation (VEE) (CI)

All meter data received by the ODS will be subjected to VEE processes. At this time, CHEC requires an ODS solution to process residential AMI data, and the VEE rules for this class of customer have been published by the IESO (*Meter Data Management and Repository (MDM/R) VEE Standard for the Ontario Smart Metering System Issue 1.0*; Attached as Appendix "B").

Bidders are expected to follow this validation process, and as part of this RFP are expected to provide a statement of compliancy that this process will be the standard implemented.

NOTE: As stated in Section 1.2 *Provincial Context for Project* it is NOT CHEC's intention to duplicate infrastructure. CHEC fully supports the intended integration with the centralized MDM/R; VEE according to the IESO rules is required so that validated data is available for CHEC's operational data requirements (i.e. load studies, etc.).

5.3.1 Data Aggregation and Analysis (CI)

The ODS will contain utility analytical tools to enable the aggregation of interval data units into billing determinant format/buckets as required by the CHEC CIS. This will include TOU buckets as provided by the OEB Regulated Price Plan (RPP), Critical Peak Pricing (CPP), and aggregated monthly consumption files for Market Participants.

In addition to data aggregation the ODS calculation engine shall also support advanced calculation capabilities including (but not limited to) the netting of bi-directional meters (enabling net-billing of bi-directional meters), auditable change tracking, the calculation of the maximum demand for any requested customers; when data is requested the proposed ODS solution will calculate (rather than utilize stored values) and calculations will be fully versioned. In addition, the ODS will fully version all formula definitions for calculated channels and registers, and track changes over time as well as corrections. If formulas change over time, the ODS will use the appropriate formula in calculations for each time period.

5.3.2 Ancillary Meter Functions

The ODS application will include the facility to trigger on-demand reads and provide the capacity for revenue protection (theft prevention). To aid in analytical capabilities, we want to ensure that the ODS has the ability to perform comparison scenarios with meter data (i.e. analyze the metering load at a transformer by creating a virtual meter with the load at the homes to perform a comparison and determine losses that exceed a certain prescribed level). The Bidder is to describe how their solution will provide these services.

5.4 Commercial and Industrial Data (I)

As per Section 3.1 *Smart Metering Infrastructure – AMI Landscape* and Section 3.4 *Scope of Work*, CHEC requires a residential ODS solution, however it is a future expectation that Commercial and Industrial data will be aggregated and analyzed within the proposed system.

Bidders are requested to provide details regarding any functionality specific to Commercial and Industrial Metering that have not been explained through responses to other sections within Section 5: *ODS Solution Technical Requirements* of this document.

5.5 ODS System Reporting (I)

To accommodate the provincial requirements for data management CHEC requires that reads missing from the previous 24-hour reporting period ending at midnight must be logged and reported through the system by 6:00 am the following morning. CHEC requires that the ODS make the following reports available according to the same timeline:

- Error,
- Process,
- Event,
- Administration,
- Interactive Graphic and Load Data,
- Statistical,
- Register,
- Manually Edited data, and
- Custom reports utilizing report writers (Crystal, COGNOS, etc).

Bidders are asked to provide description and examples of the above listed reports, and identify whether the information is provided through manually dispatched reports, or automatically dispatched reports.

It is CHEC's preference that the ODS, where possible, accommodate reporting requirements through Exception Reporting. Certain DASHBOARD functions have been identified herein which CHEC has determined would be of particular value in assisting staff with the management of the ODS functions, with the ongoing operational maintenance of AMI, and with the schedule maintenance associated with billing functions.

5.5.1 DASHBOARD: AMI SLA (AMI Performance Levels) (CI)

The ODS, by way of data validation, should be capable of determining the performance levels of the AMI network. We have included the required AMI performance levels in Section 3.3.2 *AMI Service Level Agreement* for reference. As per Section 2.8 *Grounds for Disqualification*, Bidders are required to complete compliancy statements regarding their capacity to perform the necessary audit functions.

It is CHEC's preference that the results of said audits can be displayed graphically, within one screen, or a portion of an Operations screen, demonstrating (at a glance) that the AMI is performing to the required levels and that the ODS functionality allow for the ability to generate emails on exception to advise users when the SLA has not been met. In the event that the AMI is encountering problems, the user should be able to click on the interactive DASHBOARD function and be provided with additional information to explain the problems being encountered (i.e. list of meters not reporting, etc).

If the Bidder does not have a DASHBOARD function to provide this information this should be clearly stated. In this case the Bidder should provide information regarding the level of exception reporting that is inherent to the system, and which might be utilized to determine the level of performance of the installed AMI.

5.5.2 DASHBOARD: Operational Data/Indicators/Events (CI)

It is CHEC's preference that the events produced by the AMI system (outage notification, restoration notification, tamper information, hi/lo voltage indicators, etc) can be displayed graphically, within one screen, or a portion of an Operations screen. In the event that the AMI is encountering problems, the user should be able to click on the interactive DASHBOARD function and be provided with additional information to explain the problems being encountered (i.e. list of meters experiencing power outage, events received to indicate tamper, etc)

If the Bidder does not have a DASHBOARD function to provide this information this should be clearly stated. In this case the Bidder should provide information regarding the level of exception reporting that is inherent to the system, and which might be utilized to efficiently capture events being produced by the AMI.

5.5.3 DASHBOARD: Billing Schedule Maintenance (CI)

It is CHEC's preference that ODS will be able to graphically display, within one screen, or a portion of a billing screen, the current status of the billing schedule. Required information would include cycles billed, cycles pending billing, cycles which have completed validation within the ODS, and cycles being read, as well as the scheduled dates associated with these processes.

If the Bidder does not have a DASHBOARD function to provide this information this should be clearly stated. In this case the Bidder should provide information regarding the level of exception reporting that in inherent to the system, and which might be utilized to efficiently capture events being produced by the AMI.

5.5.4 Reporting: Multiple Systems (I)

It is expected that the operational and performance reporting requirements described through Section 5.5 *ODS System Reporting* will be possible across all meter reading technologies that have been integrated within the ODS, and the ODS will track which meters are to be read by each meter reading technology and the progress of these systems as they deliver data. The ODS will be able to report on the quantity, quality, and timeliness of collected data.

5.5.5 Reporting: Graphing (I)

It is expected that the ODS will provide the ability to produce data graphs and reports for all metered and calculated channels. The system will be flexible, including such functionality as the ability to perform calculations at the time of producing graphs and reports (i.e. the graph or report will calculate and display the result). All graphs and reports shall be viewed within the ODS application user interface, as well as contain the functionality to enable data export to spreadsheets, or be transportable to other electronic file format, and saved as images for use in external reports, etc. Reports will be required to be run in either online or batch mode.

5.5.6 Reporting: Custom Queries (C)

The ODS will be capable of executing custom queries to accommodate any areas where standard reports are not available. The successful Bidder will be required to provide full database documentation (i.e. Data Model Diagrams, Table Relationships, Field Definitions).

As part of their submission, the Bidder should provide a description of how the service is managed in terms of assisting the End-User to understand the data base structures and relationships, the creation/promotion of optimal data queries, and the prevention of machine degradation due to the use of unoptimized queries.

5.5.7 ODS Access

CHEC requires that the system be configured in a "Thin Client" so that utility users can access and view data, and as a means to download data in spreadsheet format for ad hoc analysis. Bidder should provide detailed information pertaining to the flexibility and functionality of the proposed solution in this regard, and clearly define the software components residing on the server side and any software components residing on the client side.

5.6 Meter Event Manager (I)

The Bidder should describe their solution's event management capabilities with regards to receiving, storing, filtering, normalizing, and transferring event data received from any/all meter reading systems. Event data can include power loss, power restore, tamper, tilt, low battery alarms, sags/swells, etc. Event messages from different meters and/or reading systems will be standardized by the ODS solution so that a downstream outage management system can receive the same message for "power off" or "power on" regardless of which meter reading data collection system returned said event. All events received will be stored in the ODS database.

The ODS shall also provide power outage event filtering, such that the downstream outage management system receives only relevant event types, such as power off and power on that are more current than some predefined time period. Event reporting for a given meter shall also be filtered temporarily by the ODS during meter installation and/or scheduled maintenance such that false outages are not transferred to outage management.

5.7 ODS System Disaster Recovery Planning (CI)

The ODS system must reside in Canada, have adequate system redundancy, and the ODS service provider will have recovery planning such that hardware failure at any level of the ODS system will not result in any system downtime lasting more than 2 hours, with no loss in data.

More severe disasters, resulting from more than simple hardware failure (eg. building fire or telecommunications interruption), will be recovered from within 24 hours, with no loss in data. The recovery plan may include having access to a backup ODS server located at a geographically separated site (at least 50 km) and means to publish data on the back-up server. The ODS system provider's disaster recovery plan will include a worst-case provision to ensure that no data is lost.

The Bidder's response should include details regarding the disaster recovery planning that will accommodate both levels of disaster recovery (i.e. 2 hour and 24 hour recovery).

5.8 ODS Performance Service Levels (CI)

AMI Vendors deploying systems in CHEC's service area are expected to perform to the following service levels:

- Percent of hourly (interval) readings captured: 98% in 24 hours
- Percent of daily (register) readings captured: 98% in 24 hours
- In addition to the above requirements, 99% of all readings (99% of register, and 99% of interval) are required in 72 hours (rolling statistic), and 99.5% of all readings (99.5% of register, and 99.5% of interval) are required in 30 days (calendar statistic). These requirements will demonstrate the Vendor's ability to acquire the readings that were missed in 24 hours, over the subsequent time periods (i.e. continued commitment to acquire as many readings as possible).
- Percent of meters communicated within 24 hours: 99.9% (while it is conceded that some meters may be difficult to communicate with, and therefore acquire 100% of the readings 100% of the time, the aim of this statistic is to show that 99.9% of meters can be reached on a daily basis).

It is CHEC's expectation that the ODS system will be able to definitively determine whether the AMI network is satisfying these requirements. The ODS system provider should provide sufficient details to explain how their solution will be able to corroborate the AMI's performance to these service level expectations.

In addition to substantiating the AMI service levels, it is expected that the ODS will provide:

- 99.7% uptime (i.e. 2 hours per month downtime)
- Validated data files within 12 hours (interval data)
- Meter events files within 24 hours
- Alarm notification files immediately (given that the AMI can provide this data, the ODS is expected to filter/scrub alarms against known service orders from CIS)

5.9 Scalability (CI)

The Bidder must describe its proposed ODS data model demonstrating the model's flexibility and scalability to deliver cumulative and interval metering over the next ten years. The system should be designed for a minimum of 250,000 customers, assuming 2 years of online interval data and 7 years off-line data storage. Please specify the methodology for data storage and retrieval.

5.9.1 Ongoing Resource Requirements

Bidders should indicate to CHEC the expected level of resources that is expected to be required for ongoing operation of the proposed ODS solution. CHEC expects that the ODS solution will be managing their entire electric meter population by end 2010. Assuming a meter population growth resulting for the implementation of gas and/or water AMI, the Bidder should explain how the required resources would be expected to change (or not), beyond 2010.

5.10 ODS System Security (CI)

It is essential that the ODS system have, as a minimum, end-to-end protection against cyber attack and unauthorized intrusions. The Bidder should describe how its ODS ensures against loss or tampering of data. Security requirements are needed to manage the level of access users have, and the Bidder's ODS solution should meet the following minimum standards:

i. The system will contain System Administration and Security Management functions
ii. The system shall support tiered user access levels, to ensure separation of access according to the user's roles and responsibilities.
iii. The system will allow access (with appropriate permissions) to Raw AMI data, VEE formatted data, and Manually Edited data.
iv. Read-only access shall be provided for accessing data by customer, by Site-ID account, or by meter for users for whom those are the reference points, including the ability to reference and search by historical IDs or names and effective dates after changes have been made.
v. All corrections of errors with these entities should also be maintained within the ODS. Functionality should exist to allow comparisons between versions, and also allow previous versions to be restored. For all changes and correction made, information about who (or what system) made the change, when the change was made, and why the change was made shall be maintained and made available through the use of audit logs.
vi. The ODS should be able to integrate to an LDAP directory service for user authentication. This provides the user credentials required for controlling access to the LDC system resources (eg. networks and servers for both external and internal users).

Section 6: Price Submission Requirements

Please note that all documentation must reflect current capabilities. Any future capabilities must be stated as such, and a development schedule outlined.

Describe in detail the pricing for the systems proposed. Detail any assumptions made in the proposed solution and pricing. All of this information should be included within the Pricing and Functionality Spreadsheet. **As per Section 2.4 *Proposal Format Instructions*, any hard copies of the pricing submission should be submitted in a separate envelope, marked "PRICE OFFER".**

In addition to the minimum functionality required by the Ministry of Energy, CHEC is interested in the ability to support load control devices, and multi-utility meters, as this capability is in line with both the intent of the Ministry of Energy, and the service goals of CHEC members. Therefore, in addition to the current data collection requirements outlined in Section 3.3.2 *AMI Service Level Agreement*, CHEC expects to increase non-scheduled data communications to the network. These anticipated communications would in all likelihood include only specific areas, and affect low volumes of meters during any one communication.

6.1 Pricing and Compliancy Submission

The Pricing Spreadsheet allows for the Bidder to provide two options for the proposed ODS Infrastructure:

1) Within the tab labelled "Pricing_Option1_ASP" Bidders are required to submit pricing (Capital and 15 year Operating costs) for the proposed ODS Solution, as per the requirements of this RFP document (i.e. ASP model, with capability to accept Sensus AMI network data, perform AMI audit, etc.).
2) Within the tab labelled "Pricing_Option2" Bidders have the option to provide pricing alternative to that provided through Option 1. **NOTE: Pricing Option 1 is required, Pricing Option 2 is optional.** Currently the tab is structured for a license bid price submission, however the Option 2 tab has been provided in the event that Bidders feel that Pricing outside of an ASP model can better represent their model, and will allow Bidders to be creative in demonstrating the value of their solution (i.e. Bidders are free to modify the tab to demonstrate such options as higher upfront capital to allow decreased O&M costs, etc.).

6.2 Incremental Costs

In addition to the Pricing Options described in Section 6.1 *Pricing and Compliancy Submission*, Bidder's are required to submit the incremental cost for any functionality that is discussed in their proposal which does not come standard with their product. If an incremental cost is not provided, it is CHEC's understanding that the functionality comes standard with the product being proposed.

Section 7: Contract Terms and Conditions

7.1 Commencement of Contract Time

The successful Vendor shall be notified by CHEC of acceptance of the Vendor's Submission by CHEC sending a Purchase Order. The Vendor shall acknowledge receipt within ten days of the date of sending of the Purchase Order.

The Contract Time shall commence to run on the effective date indicated in the Purchase Order. Vendor shall start to perform the work on the date when the Contract Time commences.

7.2 Vendor Claims

All claims of the Vendor and all questions relating to the interpretation of the Contract, including all questions as to the acceptable fulfillment of the Contract on the part of the Vendor and all questions as to compensation, shall be submitted in writing to the CHEC Project Manager for determination.

All such determinations and other instructions of CHEC will be final unless the Bidder shall file with CHEC a written protest, stating clearly, and in detail the basis thereof, within fifteen (15) calendar days after CHEC notifies the Bidder of any such determination or instruction. CHEC will issue a decision upon each such protest within fifteen (15) calendar days and its decision will be final. Work will not be undertaken until a written final decision is rendered.

7.3 Changes in the Work

CHEC, without invalidating the Contract, may direct the Vendor to perform extra work or make changes in the work, provided that all changes or additions form an inseparable part of the work contracted for. Vendor shall make such changes or additions only after receipt of written instructions to do so from CHEC. If such changes or additions cause an increase or decrease in the cost of the Contract, or in the time required to complete the Contract, the adjustment to the contract price or time frames shall be as set out in the Change Order and the Contract shall be modified accordingly.

When a change is ordered, a change order shall be executed by CHEC and the Vendor before any change order work is performed. Any increase or decrease in the contract price and the time required for the completion of the contract work due to a change order shall be specifically set out in the change order. All terms and conditions contained in the Contract documents shall be applicable to change order work. The amount of any increase or decrease shall be added to or subtracted from the contract price as appropriate.

7.4 Delays & Extension of Time

If the Vendor is delayed at any time in the progress of the work by any act or neglect of CHEC, or any cause beyond the Vendor's reasonable control, he shall file with CHEC a notification that an extension of the Contract period is required.

The CHEC Project Manager shall review said notice and to the extent that the Vendor can reasonably demonstrate to CHEC Project Manager that it shall be delayed in its fulfillment of these terms and conditions and other obligations of this transaction due to a cause beyond its control, a reasonable extension period shall be granted.

7.5 Termination of Right to Proceed

CHEC may, in writing, terminate this Contract in whole or in part at any time, either for CHEC's convenience or for the default of the Vendor. Upon such termination, all data, plans, specifications, reports, estimates, summaries, completed work and work in process, and such other information and materials as may have been accumulated by the Vendor in performing this Contract shall, in the manner and to the extent determined by CHEC, become the property of CHEC. If the termination is for the convenience of CHEC and without default by the Vendor, an equitable adjustment for the Vendor's direct costs and profit for work actually performed shall be made by mutual agreement between the Vendor and CHEC. No amount shall be allowed for anticipated profit on unperformed services. Any expense incurred because of cost of completion by CHEC is chargeable to and shall be paid by the Vendor. The total liability to the Vendor shall be limited to the Contract value less the value of any equipment, material or completed services retained by CHEC member utilities.

Default occurs if the Vendor (1) abandons the work called for hereunder, (2) files a voluntary petition in bankruptcy or fails to obtain dismissal of an involuntary petition in bankruptcy within sixty (60) days after the filing thereof or has a Receiver/Trustee appointed, (3) becomes insolvent, (4) assigns this Contract or sublets any part of the work hereunder without prior written permission of CHEC, (5) repudiates the Contract, (6) allows liens to be filed against property of CHEC, (7) fails to meet or perform its obligations hereunder after five days notice or continues in chronic default of its obligations, (8) disregards laws, ordinances, rules and regulations related to the Contract and the work or disregards instructions of CHEC, (9) fails to complete the work in accordance with the Contract.

7.6 Right to Operate Unsatisfactory Equipment

If the operation or use of the materials or equipment after delivery and/or installation does not comply with the technical requirements set out in the Contract Documents to CHEC, CHEC shall have the right to operate and use such materials or equipment until such deficiency can be reasonably corrected provided that the period of such operation or use pending correction shall not impede or delay the ability of the Vendor to perform corrections. Such operation and use shall not constitute an acceptance of any part of the work, nor shall it relieve Vendor of any requirements of the Contract, nor shall it act as a waiver by CHEC of any requirement of the Contract.

7.7 Casualty Insurance

Before commencing work under this contract the Vendor at his own expense shall submit Certificates of Insurance, providing evidence acceptable to CHEC indicating that the Vendor has obtained and will maintain insurance for the duration of the contract. The following requirements apply to all Certificates of Insurance:

1) The insurance shall be written by an insurer acceptable to CHEC,
2) The insurance shall be primary to any coverage carried by CHEC.
3) The Vendor further agrees to provide CHEC with an executed Certificate of Insurance before commencement of work, and with written copies of the insurance policies at any time upon the written request of CHEC.
4) The Certificate of Insurance shall be an original copy signed by an authorized representative of the insurance carrier(s). (Note – faxed copies may be accepted initially to be followed up by originals in a reasonable length of time.)
5) The Certificate of Insurance shall provide that no less than 30 days advance notice will be given in writing to CHEC prior to cancellation, termination or alteration of the insurance coverage. CHEC shall be named as an additional insured on each General Liability Insurance Policy and any Excess Liability Policy or Umbrella Policy used to meet the required general liability limits.

The types of coverage and minimum limits are as follows:

1) GENERAL LIABILITY*
   a) $4,000,000 each occurrence
   b) $6,000,000 general aggregate
2) AUTOMOBILE LIABILITY*
   a) Bodily injury $1,000,000 per person
   b) $1,000,000 per accident
   c) Property damage $500,000 or
   d) Combined Single Limit $1,000,000

** A blanket, umbrella, and/or excess liability policy(s) may be utilized to increase limits to the desired level(s).*

7.8 Subcontractors

CHEC reserves the right to refuse to permit any person or organization (subcontractor) to participate in the work covered by this Contract, such refusal shall not be unreasonably imposed. No subcontract shall relieve the Vendor of any liabilities or obligations under the Contract, and the Vendor agrees that Vendor is fully responsible to CHEC for the acts and omissions of Vendor's subcontractors and of persons employed by them. Vendor shall require every subcontractor to comply with the provisions of the Contract.

7.9 Payment

Payment shall be made based upon completion of the performance milestones itemized below.
Vendor shall submit to CHEC a request for payment for each milestone that has been met. Payment for each milestone shall also be contingent on successful completion of the preceding milestones.

1) Fifteen percent (15%) of the contract price will be paid after the successful Acceptance Test, which requires delivery and integration of the system head-end.
2) Twenty five percent (25%) of the contract price will be paid after delivery of 35% of the communication infrastructure and 35% of the new meters and other customer premises equipment.
3) Twenty percent (20%) of the contract price will be paid upon successful installation, operation and route Acceptance of the equipment described in (2) above and delivery of an additional 30% all equipment on CHEC's system.
4) Twenty percent (20%) of the contract price will be paid upon successful installation, operation and route Acceptance of the equipment described in (3) above and delivery of all remaining system elements.
5) Twenty percent (20%) upon completion of system installation, Acceptance of all routes, and delivery of all documentation, judged by CHEC to be acceptable, in any event not longer than 90 days after complete installation.

CHEC will make payment within thirty (30) days of receipt of a request for payment, if above conditions are met.

When the Vendor has completed all work in accordance with the terms of the Contract Documents, the Vendor shall submit to CHEC a request for final payment. The request for final payment shall constitute a waiver of all claims by the Vendor except for claims specifically listed in the request.

Vendor's submission of its request for final payment shall constitute its warrant that the Vendor has to the best of its knowledge fully completed all work included in the Contract and has fully paid for labour, materials, equipment, services, taxes and all other costs and expenses resulting from this Contract.

7.10 Acceptance

These terms and conditions becoming binding when the Vendor's Submission chosen for acceptance by CHEC is given written notice of acceptance of the submission.

No modification hereof and no condition stated by Vendor in accepting or acknowledging this order, which is in conflict or inconsistent with, or in addition to the terms and conditions set forth herein, shall be binding upon CHEC unless accepted in writing by CHEC.

7.11 Shipments

Vendor shall mail Bill of Lading and Shipping Memo to destination, and CHEC's Project Manager.

Vendor shall notify the CHEC Project Manager promptly if unable to make shipment. Shipments shall be made to multiple destinations in CHEC's service territory for logistical convenience. Such shipment instructions will be stated in the purchase contract that will be developed between the selected Vendor and CHEC.

7.12 Prices

Vendor agrees that prices are firm unless otherwise noted, and Vendor warrants that said prices do not exceed the prices allowed by any applicable Federal, Provincial or Local regulation.

7.13 Compliance with Laws

Vendor warrants that in performing work under this order Vendor will comply with all applicable laws, rules and regulations of governmental authorities and agrees to indemnify and save CHEC harmless from and against any and all liabilities, claims, costs, losses, expenses, and judgments arising from or based on any actual or asserted violation by the Vendor of any such applicable laws, rules and regulations.

7.14 Patents

Vendor agrees to protect and save harmless CHEC from all costs, expenses or damages, arising out of any infringement of claim or infringement or Patents in CHEC's use of material or equipment furnished pursuant to this order.

7.15 Assignment

Vendor agrees that neither this order nor any interest herein shall be assigned or transferred by Vendor except with the prior written approval of CHEC.

7.16 Substitution

No substitution will be permitted under this order except on specific written authority of CHEC's Project Manager.

Appendix A

Ministry of Energy (MoE)
Functionality Specification for an
Advanced Metering Infrastructure
Version 2 (Dated July 5, 2007)

FUNCTIONAL SPECIFICATION

FOR AN

ADVANCED METERING INFRASTRUCTURE

VERSION 2

July 5, 2007

FUNCTIONAL SPECIFICATION

FOR AN ADVANCED METERING INFRASTRUCTURE

Table of Contents

FUNCTIONAL SPECIFICATION

FOR AN ADVANCED METERING INFRASTRUCTURE

1.0 APPLICATION OF SPECIFICATION

This Specification sets the required minimum level of functionality for AMI in the Province of Ontario for residential and small general service consumers where the metering of demand is not required. This Specification is not intended to apply to net metering applications.

2.0 FUNCTIONAL SPECIFICATION

2.1 Deployment

This Specification shall be met regardless of the size or scope of the AMI deployment by a distributor.

2.2 Minimum Functionality

2.2.1 As a minimum:

2.2.1.1 AMI shall collect Meter Reads on an hourly basis from all AMCDs deployed by a distributor and transmit these same Meter Reads to the AMCC and MDM/R, as required, in accordance with these Specifications; and

2.2.1.2 A Meter Read shall be collected, dated and time stamped at the end of each hour (i.e. midnight as represented by 24:00).

2.2.2 The date and time stamping of Meter Reads shall be recorded as year, month, day, hour, minute (i.e. YYYY-MM-DD hh:mm).

2.2.3 All meters shall have a meter multiplier of one (1).

2.2.4 Distributors shall provide the MDM/R with the service multiplier for transformer-type meters.

2.3 Performance Requirements

2.3.1 Collection and Transmission of Meter Reads:

2.3.1.1 AMI shall successfully collect and transmit to the AMCC and MDM/R at least 98.0% of the Meter Reads from all AMCDs deployed by a distributor in any Daily Read Period.

2.3.1.2 Meter Reads unsuccessfully collected or transmitted shall not be due to the same AMI component (including, without limitation, any AMCD) during any three (3) month consecutive time period.

2.3.1.3 AMI shall be able to collect and transmit Meter Reads during its operating life without requiring a field visit.

2.3.2 Transmission Accuracy: Over the Daily Read Period, 99.9% of the Meter Reads received by the AMCC shall contain the same information as that collected by all AMCDs deployed by the distributor.

2.3.3 AMI shall be capable of providing Meter Reads with a precision of at least 10 Watt-hours (0.01 kWh).

2.4 Technical Requirements

2.4.1 When an AMI includes AMRCs, the AMRCs shall have the ability to store meter data to accommodate the performance requirements in section 2.3.1.

2.4.2 Time Synchronization:

2.4.2.1 AMI shall be operated and synchronized to Official Time, as set by the National Research Council of Canada.

2.4.2.2 AMI shall have the capability of adjusting for changes due to local daylight savings time.

2.4.2.3 AMI installed within a distributor’s service area shall have the capability of accommodating more than one (1) time zone.

2.4.2.4 Time synchronization shall be maintained in the AMI to the specified accuracy parameters set out in section 2.4.3.1 following a loss of power.

2.4.2.5 All Meter Reads shall adhere to accurate time synchronization processes to ensure an accurate accounting of electricity consumption at each meter.

2.4.3 Time Accuracy:

2.4.3.1 At all times, time accuracy in the AMI shall not exceed a ±1.5 minute variance from the time established in section 2.4.2.1.

2.4.3.2 AMI shall be able to prove that time accuracy does not exceed the permitted time variance identified in section 2.4.3.1.

2.4.4 Loss and Restoration of Power:

2.4.4.1 AMI shall detect and identify the interval in which a loss of power occurred during a Daily Read Period.

2.4.4.2 AMI shall detect and identify the interval in which power was restored following a loss of power.

2.4.5 Environmental Tolerances: All AMI components (except the AMCC) shall operate and meet the requirements in these Specifications within a temperature range of minus thirty degrees Celsius (–30° C) to positive sixty-five degrees Celsius (+65° C), and within a humidity range of zero percent (0%) to ninety-five percent (95%) non-condensing.

2.5 Advanced Metering Communication Device (AMCD)

2.5.1 Installation Within the Meter:

2.5.1.1 The AMCD shall not impair the ability of the meter to be visually read.

2.5.1.2 Meters in which an AMCD is installed shall be able to be installed in existing meter sockets or enclosures.

2.5.1.3 AMCD shall meet or exceed ANSI standards to withstand electrical surges and transients.

2.5.2 Labelling:

2.5.2.1 The AMCD shall be permanently labelled with:

(1) Legally required labelling;

(2) Manufacturer's name;

(3) Model number;

(4) AMCD identification number;

(5) Input/output connections;

(6) Date of manufacture; and

(7) Bar code for tracking and inventory management.

2.5.3 When installed at a consumer's location, the meter shall visibly display, as a minimum, the AMCD identification number, meter serial number and LDC badge number for the meter.

2.5.4 The AMCD shall be able to be initialized or programmed during, or prior to, field installation.

2.6 Transmission of Meter Reads

2.6.1 All Meter Reads collected during the Daily Read Period shall be received by the AMCC and transferred to the MDM/R no later than 5:00 a.m. local time following the Daily Read Period.

2.6.2 Meter Reads are not required to be transmitted in a single transmission and may be transmitted as frequently as necessary in order to meet the requirements in section 2.6.1.

2.6.3 AMCC shall transfer the information identified in section 2.6.1 using an approved protocol and file structure.

2.7 Advanced Metering Regional Collectors (AMRC)

2.7.1 LAN Communication Infrastructure:

2.7.1.1 The spectrum allocation and wattage of the radio signal used by an AMI shall not impede neighbouring frequencies.

2.7.2 When an AMI includes AMRCs:

2.7.2.1 The AMI shall provide for the continuous powering of AMRCs regardless of their location and placement.

2.7.2.2 All AMCDs shall be able to collect and transmit Meter Reads when one or more AMRC has a loss of power.

2.7.2.3 Memory and software parameters shall be maintained at all AMRC during a loss of power, whether by the provision of backup/alternate power or other solution.

2.8 Advanced Metering Control Computer (AMCC)

2.8.1 Each AMCC shall have the ability to store a rolling sixty (60) days of Meter Reads.

2.8.2 A distributor shall not aggregate Meter Reads into rate periods or calculate consumption data from the Meter Reads collected through its AMI either in its AMCC or any other component.

2.8.3 The AMCC shall be able to perform basic operational verification of Meter Reads received before transmitting these Meter Reads to the MDM/R.

2.9 Customer Account Information

2.9.1 Distributors shall provide initial information associated with customer accounts to the MDM/R on a date to be determined.

2.9.2 On an ongoing basis, distributors shall provide information associated with any change to the initial information identified in section 2.9.1 to the MDM/R at a frequency to be determined.

2.9.3 Information to be provided to the MDM//R pursuant to sections 2.9.1 and 2.9.2 is to be determined.

2.10 Monitoring & Reporting Capability

2.10.1 The AMI shall have non-critical reporting functionality and critical reporting functionality as required in this section 2.10. Information generated from this reporting functionality shall be available to the MDM/R.

2.10.2 Non-critical reporting:

2.10.2.1 At the completion of every Daily Read Period and following a transmission of Meter Reads, the AMCC shall generate a status report that includes information regarding anomalies and issues affecting the integrity of the AMI or any component of the AMI including information related to any foreseeable impact that such anomalies or issues might have on the AMI's ability to collect and transmit Meter Reads.

2.10.2.2 In addition to section 2.10.2.1, the AMCC shall generate reports:

(1) Confirming successful initialization of the AMCD's installed in the field;

(2) Confirming data linkages among an AMCD identification number, LDC badge number, serial number and customer account;

(3) Confirming that the MDM/R has successfully received notification of any changes to customer account information;

(4) Confirming that the AMCC has successfully made changes to customer account information following receipt of same from the MDM/R;

(5) Confirming the successful collection and transmission of Meter Reads or logging all unsuccessful attempts to collect and transmit Meter Reads, identifying the cause, and indicating the status of the unsuccessful attempt(s) pursuant to section 2.3.1;

(6) Confirming the accuracy of the Meter Reads received by the AMCC pursuant to section 2.3.2;

(7) Confirming that all Meter Reads have a precision of at least 10 Watt-hours (0.01 kWh) pursuant to section 2.3.3;

(8) Confirming whether the Meter Reads acquired within the Daily Read Period are in compliance with the time accuracy levels identified in section 2.4.3;

(9) Confirming whether time synchronization within the AMI or any components of the AMI has been reset within the Daily Read Period;

(10) Identifying the intervals in which a loss of power occurred and at which power was restored, following a loss of power;

(11) Addressing the functionality of the AMCD communication link, including status indicators related to the AMCD and AMRC;

(12) Identifying suspected instances of tampering, interference and theft;

(13) Flagging potential network, meter and AMCD issues; and

(14) Identifying any other instances that impact or could potentially impact the AMI's ability to collect and transmit Meter Reads to the AMCC and/or MDM/R on a daily basis.

2.10.2.3 Following a transmission of Meter Reads or at the completion of every Daily Read Period, the information in section 2.10.2.2 (5) shall be stored and used by the AMCC to assess compliance with the requirement specified in section 2.3.1.2.

2.10.2.4 The reports generated in sections 2.10.2.1 and 2.10.2.2 shall be made available to the MDM/R with a frequency to be determined.

2.10.3 Critical reporting:

Critical events are defined to include any AMI operational issue that could adversely impact the collection and transmission of Meter Reads during any Daily Read Period.

2.10.3.1 The AMI shall identify and report the following to the distributor:

(1) AMCD failures;

(2) AMRC failures;

(3) Issues related to the storage capacity of any component of the AMI;

(4) Communication links failures;

(5) Network failures; and

(6) Loss of power and restoration of power.

2.10.3.2 The reports generated in section 2.10.3.1 shall be made available to the MDM/R.

2.11 Security and Authentication:

2.11.1 The AMI shall have security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements.

2.12 Proven Technology

2.12.1 The AMI shall be a technology that has been proven to reliably comply with these Specifications.

2.13 Regulatory Requirements

2.13.1 The AMI shall meet all applicable federal, provincial and municipal laws, codes, rules, directions, guidelines, regulations and statutes (including any requirements of any applicable regulatory authority, agency, board, or department including Industry Canada, the Canadian Standards Association, the Ontario Energy Board and the Electrical Safety

Authority) (collectively, "**Laws**"). For greater certainty, the AMI shall meet all applicable Laws that are necessary for the measurement of data and/or the transmission of data to and from the consumers within the Province of Ontario, including Laws applicable to metering, safety and telecommunications.

2.14 Water or Natural Gas Meter Reads

2.14.1 The AMI should be capable of supporting an increased number of Meter Reads associated with the reading and transmission of water and/or natural gas meters through additional ports on the AMCD, through optionally available multi-port AMCDs, or through additional AMCD/AMRC devices that are compatible with operating on the AMI. When procuring AMI, distributors shall obtain an indication of the capabilities of the proposed AMI to read water and natural gas meters, indicating the makes and models of such meters that can be read, and any requirements for retrofitting them.

3.0 DEFINITIONS

Within this Specification the following words and phrases have the following meanings:

"AMCC" is an advanced metering control computer that is used to retrieve or receive and temporarily store Meter Reads before or as they are being transmitted to the MDM/R. The information stored in the AMCC is available to log maintenance and transmission faults and issue reports on the overall health of the AMI to the distributor.

"AMCD" is an advanced metering communication device that is housed either under the meter's glass or outside the meter. It transmits Meter Reads from the meter directly or indirectly to the AMCC.

"AMI" means an advanced metering infrastructure. It includes the meter, AMCD, LAN, AMRC, AMCC, WAN and related hardware, software and connectivity required for a fully functioning system that complies with this Specification. With some technologies, an AMI does not include AMRCs. An AMI does not include the MDM/R.

"AMRC" is an advanced metering regional collector that collects Meter Reads over the LAN from the AMCD and transmits these Meter Reads to the AMCC.

"consumer" or "customer" means a person who uses, for the person's own consumption, electricity that the person did not generate.

"distributor" has the meaning provided in the *Ontario Energy Board Act, 1998*.

"Daily Read Period" means the 24-hour period for collecting Meter Reads, subject to the two periods annually during which changes to and from daylight savings time take place. The Daily Read Period ends at 12:00 midnight of each day.

"LAN" means a local area network, the communication network that transmits Meter Reads from the AMCD to the AMRC.

"meter multiplier" is the factor by which the register reading must be multiplied to obtain the registration in the stated units.

"Meter Read" is a number generated by a meter that reflects cumulative electricity consumption at a specific point in time.

"MDM/R" means the meter data management and meter data repository functions within which Meter Reads are processed to produce rate-ready data and are stored for future use.

"Specification" means these functional specifications.

"transformer-type meter" means a meter designed to be used with instrument transformers.

"WAN" means a wide area network, the communication network that transmits Meter Reads from the AMRC to the AMCC or, in some systems from the AMCD directly to the AMCC, and from the AMCC to the MDM/R.

Appendix B

Meter Data Management
and Repository (MDM/R)
VEE Standard for the
Ontario Smart Metering System
Issue 1.0

STANDARD

Meter Data Management and Repository (MDM/R)

VEE Standard for the Ontario Smart Metering System

Issue 1.0

This document provides the Standards for Validation, Estimation, and Editing of Meter Read Data performed by the MDM/R for the Ontario Smart Metering System

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Status of this Standard

This document was placed under formal change control on March 20, 2008 with the posting of Issue 1.0. However, as of this date, portions of Sections 3, 4, 5, 6 and 7 pertaining to Commercial & Industrial metering are still under review and may be subject to revision. These sections have been highlighted in "yellow".

Document ID	IESO_STD_0078
Document Name	Meter Data Management and Repository (MDM/R) - VEE Standard for the Ontario Smart Metering System
Issue	Issue 1.0
Reason for Issue	VEE Standard issued under formal change control.
Effective Date	March 20, 2008

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Document Change History

Issue	Reason for Issue	Date
0.1	Draft VEE Standard for discussion with SMSIP Working Group	January 3, 2007
0.2	Updated and presented to the SMSIP Working Group Sub-committee	January 8, 2007
0.3	Updated and presented to the SMSIP Working Group Sub-committee	January 12, 2007
0.4	Updated with SMSIP Working Group Sub-committee	January 14, 2007
0.5	Updated with Input from Sub-committee members	January 25, 2007
0.6	Updated with Information from the MDM/R Detail Design Document Version 1.9	March 15, 2007
0.7	Updated to incorporate changes per the review of the VEE Sub-Committee	March 19, 2007
0.8	Update of Table 7-5 Default VEE Services Configuration	March 22, 2007
0.9	General revision to reflect additional detail provided in Version 2.0 of the Detailed Design	March 7, 2008
1.0	Document placed under formal change incorporating input of the SMSIP Working Group VEE Sub-Committee	March 20, 2008

Related Documents

Document ID	Document Title	Issue
Ontario Regulation 440/07	*Functional Specification for an Advanced Metering Infrastructure – Version 2*	July 5, 2007
Ontario Energy Board	*Distribution System Code*	Last Revised on June 27, 2007
MDM/R Detailed Design	*Meter Data Management and Repository MDM/R V1.0 Detailed Design Version 2.0*	March xx, 2008
IESO_SPEC_9027	*MDM/R V1.0 Technical Interface Specifications Version 2.3*	30 November 2007
SME_SPEC_0001	*MDM/R V1.0 Reports Technical Specifications Version 2.6*	14 February 2008
Ontario Energy Board Smart Meter Implementation Plan	*Draft Report of the Board For Comment*	November 9, 2004
SOR/86-131	*Electricity and Gas Inspection Regulations*	January 28, 2008

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Table of Changes

The following is a summary of changes to this document from Issue 0.8 dated March 22, 2007.

Reference (Section and Page)	Description of Change
Title Page	• Revised document title
Related Documents	• Updated reference to AMI Function Specification • Updated reference to Distribution System Code • Updated reference to MDM/R Detailed Design Document • Added references to MDM/R Technical Interface Specifications and MDM/R Reports Technical Specifications • Added reference to the Electricity and Gas Inspection Regulations
Section 1, pages 1-3	• Updated role of the OEB as described in the Introduction • Added assumptions regarding net metering and metering for all classification of generators • Updated description of Section 2
Section 2, pages 7-14	• Expanded description of AMI Quality and Completeness tests and Data Quality flags • Relocated and updated new Section 2.3.1 from Section 3 • Relocated and updated new Section 2.3.2 from Section 4 • Added new Section 2.3.3 providing descriptions of Data Collection and VEE Reports
Section 3, pages 15-22	• General re-organization of this section for clarity (changes not tracked) • Update throughout to describe ‘message’ validation services • Update of descriptions of all validation checks to provide greater specificity • Added initial draft of validation services for C&I metering
Section 4, pages 23-29	• General re-organization of this section for clarity (changes not tracked) • Update throughout to describe ‘message’ estimation routines • Update of descriptions of all estimation routines to provide greater specificity • Added initial draft of estimation services for C&I metering
Section 5, page 33	• Added initial draft of editing support for C&I metering
Section 6, pages 35-37	• Update of descriptions of Billing Validation Sum Check to provide greater specificity • Added initial draft of estimation services for C&I metering

Section 7, pages 39-52	• General re-organization of this section for clarity (changes not tracked) • Update throughout to describe 'message' validation and estimation routines • Update of descriptions of all validation and estimation parameters to provide greater specificity • Update of descriptions of Billing Validation Sum Check parameters to provide greater specificity • Additions to VEE Services tabulation to reflect additional parameters • Added placeholder for C&I metering VEE Services
Section 7.2, Table 7-5, pages 50-51	Updates to validation parameters for default VEE Services based on review and input by the SMSIP Working Group VEE Sub-Committee • Confirmed application of the Maximum Demand Check to VEE Services 02, 03, 04, 05, 06, and 07 by setting 'Maximum Demand Check' check service parameter to "Y" • Confirmed application of the Consecutive Zeros Check to VEE Services 02, 03, 04, 05, 06, and 07 by setting 'Consecutive Zeros Check' check service parameter to "Y" Updates to estimation parameters for default VEE Services based on review and input by the SMSIP Working Group VEE Sub-Committee • Disabled Linear Interpolation for VEE Services 03, 04, 05, 06, and 07 setting 'Max Interpolation Minutes' to zero • Confirmed use of Register Read Scaling for VEE Services 03, 04, 05, 06, and 07 setting 'Register Read Allocation' parameter to "Y" • Confirmed use of Newest Like Day for VEE Services 03, 04, 05, 06, and 07 setting 'Newest Like Day Method' parameter to "Newest Like Day" and 'Newest Like Day Limit' parameter to "1" day • Confirmed use of Class Load Profile estimation only for VEE Service 07 – Seasonal establishing the following parameter settings: o 'Use Class Load Profiles' = "Y" o 'Class Profile ADU Min Days' = 5 days o 'Class Profile ADU Oldest Day' = 30 days o 'Class Profile ADU Newest Day' = 1 day Established initial Billing Validation Sum Check parameter settings based on review and input by the SMSIP Working Group VEE Sub-Committee • For VEE Services 01 and 02 o 'BillingSumCheck' = "N" • For VEE Services 03, 04, 05, 06, and 07: o 'BillingSumCheck' = "Y" o 'BillingSumCheckFail Action' = "Value" o 'MaxRegisterRange' = "1" hour o 'NoRegRead Action' = "Fail" o 'ThresholdType' = "Ratio" o For 03, 04, 07 'ThresholdValue' = "0.010" (i.e. 1%) o For 05 and 06 'ThresholdValue' = "0.005" (i.e. ½ %)

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1. Introduction

This document has been prepared in consultation with the sub-committee members of the SMSIP Joint Working Groups as a draft Validation, Estimation and Editing (VEE) Standard for further consideration by the Joint Working Group.

The OEB does not envision approving the VEE rules developed by the IESO SMSIP Working Group. The Board does expect that, at a minimum, the rules would comply with 5.3.2 and 5.3.3 of the *Distribution System Code*.

1.1 Purpose

The purpose of this document is to establish a province wide validation, estimation standard and editing guideline for Meter Read data collected for electricity smart meters in the province of Ontario.

1.2 Scope

The scope of this document is the validation and estimation and editing standards for smart metering used for the following:

- Residential or small general service consumers where the metering of demand is not required for single phase and three phase installations either self-contained or transformer type meters.

- Commercial and Industrial consumers where the metering of demand is required for single phase and three phase installations either self-contained or transformer type meters involving multiple channel and multiple data type metering.

1.3 Who Should Use This Document

This document should be used by Local Distribution Companies, Advance Metering Infrastructure Operators, and the Smart Metering Entity for use in applying the VEE services described herein.

1.4 Assumptions and Limitations

- Wholesale metering installations registered with the IESO are not subject to the VEE services described in this document.

- Net metering and the metering for all classifications of generators are outside the current scope of the MDM/R and the VEE Services described in this document.

- Missing meter read data that requires estimation or editing will not be reported by the MDM/R for customer presentation.

- The sub-committee members of the SMSIP Joint Working Groups preference would be that weather normalization factors be applied to estimated Meter Reads. This MDM/R functionality is not being anticipated in the initial implementation of the MDM/R unless directed by the Ontario Energy Board. Future stages of MDM/R implementation may support this functionality.

- VEE Services provided by the MDM/R shall apply only to Smart Meters that conform to the criteria described in the *Functional Specification for an Advance Metering Infrastructure*.

- The VEE Services described in this document shall only be applied to physical Service Delivery Points.

1.5 Conventions

The standard conventions followed for this document are as follows:

- The word “shall” denotes a mandatory requirement,
- Title case is used to highlight process or component names; and
- *Italics* are used to highlight publication, titles of procedures, letters and forms

1.6 Roles and Responsibilities

Role of the Smart Metering Entity

The role of the Smart Metering Entity will be the configuration and maintenance of VEE Services to be applied to Meter Read data transmitted to the MDM/R by LDCs across the province of Ontario. VEE Services beyond a set of default VEE Services may be configured by the MDM/R Administrator to support additional LDC needs. Any such additional VEE Services will be available to all LDCs.

Role of Local Distribution Companies

The role of the local distribution company shall be to apply the available VEE Services appropriately to all Service Delivery Points within their service territory.

LDC’s will be responsible to validate all Meter Read data that has been identified by the MDM/R as “Needs Validation or Editing” (NVE).

1.7 How This Document Is Organized

This document is organized as follows:

- **Section 2** of this document provides an overview of the Application of the Validation, Estimation, and Editing Standards; the AMI to MDM/R Interface, and MDM/R Data Collection and Reporting Services.

- **Section 3** of this document provides a description of Validation Standards for residential or small general service consumers where the metering of demand is not required and commercial and industrial consumers where the metering of demand is required including meters involving multiple channels and multiple data type metering installations.

- **Section 4** of this document provides a description of Estimation Standards for residential or small general service consumers where the metering of demand is not required and commercial and industrial consumers where the metering of demand is required including meters involving multiple channels and multiple data type metering installations.

- **Section 5** of this document provides a description of Editing Guidelines for residential or small general service consumers where the metering of demand is not required and commercial and industrial consumers where the metering of demand is required including meters involving multiple channels and multiple data type metering installations.

- **Section 6** of this document provides a description of the Billing Quantity Validation Services for residential or small general service consumers where the metering of demand is not required and commercial and industrial consumers where the metering of demand is required including meters involving multiple channels and multiple data type metering installations.

- **Section 7** of this document provides a description of the Validation, Estimation and Editing services for residential and small commercial consumers, commercial and industrial consumers where the metering of demand is required including meters involving multiple channels and multiple data type metering installations.

1.7.1 Definition of Terms used in this Document

Within this document the following words and phrases have the following meanings:

"**AMCC**" means the Advanced Metering Control Computer that is used to retrieve or receive and temporarily store Meter Reads before or as they are being transmitted to the MDM/R. The information stored in the AMCC is available to log maintenance and transmission faults and issue reports on the overall health of the AMI to the LDC.

"**AMI**" means the Advanced Metering Infrastructure, it includes the meter, Advanced Metering Communication Device (AMCD), Local Area Network (LAN), Advanced Metering Regional Collector (AMRC), Advanced Metering Control Computer (AMCC), Wide Area Network (WAN), and related hardware, software, and connectivity required for a fully functioning data collection system. An AMI does not include the MDM/R.

"AMCD" is an Advanced Metering Communication Device that is housed either under the meter's glass or outside of the meter. It transmits Meter Reads from the meter directly or indirectly to the AMCC.

"AMRC" is an Advanced Metering Regional Collector that collects Meter Reads over the local area network from the AMCD and transmits these Meter Reads to the AMCC.

"**Billing Quantity**" refers to consumption data that has been through VEE and is ready for use in billing.

"**Billing Multiplier**" is a factor that shall be applied to Meter Reads from metering installations where instrument transformers including current transformers (CT) and potential transformers (PT) are installed. For transformer type metering installations this factor shall be the product of the current transformer ratio, the potential transformer ratio and the meter multiplier. All conforming Smart Meters shall have a meter multiplier of one (1) in accordance with the Functional Specification for an Advanced Metering Infrastructure. Transformer loss factors for primary installations shall not be included in the determination of this factor.

Where no external instrument transformers are installed such as for self-contained meters this factor shall be one (1) in accordance with the *Functional Specification for an Advanced Metering Infrastructure*.

"Commercial and Industrial customers" refers to commercial and industrial consumers where the metering of demand for billing purposes is required.

"**Consumer**" or "**customer**" refers to residential or small general service consumers where the metering of demand is not required.

"**Daily Read Period**" means the 24-hour period for collecting Meter Reads, subject to the two periods during which changes to and from Daylight Savings Time take place. The Daily Read Period commences at 12:00 midnight of each day.

"**kWh**" means kilowatt-hour.

"**LDC**" means a Local Distribution Company, which is a LDC, as defined in the Ontario Energy Board Act, 1998.

"**Meter Read**" is a number generated by a meter that reflects cumulative electricity consumption at a specific point in time. (The Meter Read and related data will be reported to the MDM/R at a specific Service Delivery Point).

"**Meter Read Block**" is used by the MDM/R for validation and estimation purposes. All validation and estimation functions are based on acting upon a set of contiguous intervals bounded by a start register read and a stop register read. In some instances a Meter Read Block the data will span two or more Meter Transfer Blocks. For a Meter Transfer Block consisting of interval consumption data with a register reading at the end of a set of interval consumption data, the start register read for the Meter Read Block will be the immediately preceding (contiguous) stop register read.

"Meter Transfer Block" is a set of data transferred from an AMCC (or other system) to the MDM/R relating to meter reads for a specific Universal SDP ID. A Meter Transfer Block is a set of interval consumption data with a register reading at the end of the set of interval data, or a set of interval register reads for a number of contiguous intervals.

"**MDM/R**" means the meter data management and meter data repository functions within which Meter Reads are processed to produce Billing Quantity data and the storage of data for future use.

"**SDP**" means the Service Delivery Point at which delivery is metered or calculated. The SDP is the point at which billing occurs based on input from one or more smart meters.

"**VEE**" means validation, estimating and editing of Meter Reads to identify and account for missed and inaccurate reads used to derive billing data.

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2. Application of the VEE Standards

The Validation, Estimation and Editing Standards offer a series of checks that can be performed against a Meter Transfer Block. Several of the Validation and Estimation checks have variable configurable parameters. These parameters allow for the configuration of the actions taken should the Meter Transfer Block fail the various validation and/or estimation checks.

This section provides a description of the application of these standards by the Smart Meter Entity in establishing default VEE Services or specific VEE Services necessary to support additional LDC needs.

This section also provides a description of the AMI to MDM/R Interface including the quality and completeness tests that are expected to be performed by the Advance Metering Infrastructure prior to the transmission of meter read data to the MDM/R, and MDM/R Data Collection and Reporting Services.

2.1 Application of Standards

The diversity of consumer types, load usage patterns, geographic location, and other variables within Ontario necessitate the creation of a number of VEE Services. Multiple VEE Services will provide the ability to modify the validation and estimation parameters to better meet the VEE needs of a consumer group.

Default VEE Services offered to LDCs will be administered by the Smart Metering Entity and will be available for use throughout the province via the MDM/R.

Creation, maintenance and administration of any additional LDC specific VEE Services once created by the Smart Meter Entity shall be made globally available to all LDCs via the MDM/R.

2.2 AMI – MDM/R Interface

2.2.1 Quality and Completeness Tests Performed by the AMI

It is expected that certain quality and completion tests are performed by the AMI systems prior to the Meter Read data being sent to the MDM/R. Test results are in the form of interval data flags associated with the Meter Reads, in a particular Meter Transfer Block being sent to the MDM/R. These types of tests are listed below:

- Pulse Over Flow Check;
- Test Mode Check;
- Meter Diagnostic Check;

- Reverse Energy Check;
- Time Change Check; and
- Loss and Restoration of Power

Pulse Overflow Check

Pulse Overflow conditions are normally a result of improper scaling factors within the meter, improper instrument transformer sizing or a meter hardware failure. A meter sets a Pulse Overflow flag when the energy consumption in an interval exceeds the range of the interval. This flag generally indicates a serious problem with the meter installation or the meter itself. These metering conditions must be physically investigated and corrected by the LDC.

The AMI System must be capable to analyse and identify the intervals for this condition and flag them with a “PulseOverflow” flag prior to providing the Meter Read Data to the MDM/R. The MDM/R inspects Meter Read Blocks received with this condition and validates the data, estimates the data or flags it for verification or editing by the LDC based on the VEE Service parameter.

Test Mode Check

The Test Mode condition is normally performed at the metering installation by a metering technician. This test requires the meter to be placed in a test mode and possibly have a simulated load condition applied to the meter to verify the meter’s accuracy. The AMI System identifies the interval(s) where the usage is recorded by the meter in a Test Mode and provides this information to the MDM/R. Intervals received and flagged with a “test mode” indicator will be validated, estimated or flagged for verification or editing by the LDC based on the VEE Service parameter.

Meter Diagnostic Check

The AMI System may be capable to identify intervals for various meter diagnostic problem existing prior to providing the Meter Read data to the MDM/R. The Meter Read Blocks provided to the MDM/R with such conditions may be validated, estimated or flagged for verification or editing by the LDC based on the VEE Service parameter.

Reverse Energy Check

The AMI System may be capable to identify intervals for reverse energy condition exists prior to providing the Meter Read Data to the MDM/R. The Meter Read Blocks provided to the MDM/R with such conditions may be validated, estimated or flagged for verification or editing by the LDC based on the VEE Service parameter.

Time Change Check

Time change checks are performed within the AMI system to verify that the components used for data collection are within the acceptable time thresholds as described in the, “*Functional Specification for an Advanced Metering Infrastructure*.” The Time Change Flag indicates that the meter time was adjusted during the interval and the interval may be either shorter or longer than the specified interval at which the data is to be collected. Meter Read Blocks provided to the MDM/R with time change flags may be validated, estimated or flagged for verification or editing by the LDC based on the VEE Service parameter.

Loss and Restoration of Power

Loss of power is a condition where the supply of electricity to the AMCD and/or AMRC has occurred. This failure could be as a result of a LDC distribution supply failure or the operation of an electricity disconnect prior to the AMCD and/or AMRC device.

Restoration of power is a condition where the supply of electricity to the AMCD and/or AMRC has been re-established.

The AMI system shall detect and identify the interval(s) in which a loss of power occurred and identify the interval(s) in which the restoration of power occurred. These interval flags made available to the MDM/R are required to assure accurate validation and estimation of data for each SDP.

2.2.2 Data Quality Flags Provided by the AMI

AMI systems may provide additional data quality flags that will be recognized by the MDM/R and recorded as part of the meter data record.

Data quality flags do not represent validation tests but simply set data quality flags and failure codes in the MDM/R Meter Data Database. Data quality flags are applied as part of the meter data collection process. The data quality flags that are transferred vary by AMCC type and may set corresponding MDM/R flags. In addition to the quality and completeness test flags used for validation, the MDM/R will store the following data quality flags.

Partial Data

The MDM/R inspects each interval for a partial data flag. The 'PARTIAL_INTERVAL' flag is set in the Meter Data Database of each interval for which the AMCC reports a partial data condition.

Short Interval

The MDM/R inspects each interval for a short interval flag. The 'SHORT_INTERVAL' flag is set in the Meter Data Database of each interval for which the AMCC reports the interval to be shorter than the specified interval at which the data is to be collected.

Long Interval

The MDM/R inspects each interval for a long interval flag. The 'LONG_INTERVAL' flag is set in the Meter Data Database of each interval for which the AMCC reports the interval to be longer than the specified interval at which the data is to be collected.

Data Collection Estimation

The MDM/R inspects each interval for a data collection estimation flag. The 'DC_DATA_ESTIMATION' flag is set in the Meter Data Database for each interval for which the AMCC reports the interval has been estimated outside the MDM/R as part of the data collection process. This flag sets the Validation Status to EST (estimated) and sets the Change Method to EXT (external – indicating estimation performed external to the MDM/R). Other Validation checks work normally and can re-set the Validation Status; failure codes, and estimation Change Method on failure of such tests.

2.3 MDM/R Data Collection and Reporting Services

2.3.1 Meter Read Data Validation During Loading

These services are performed immediately upon receipt of the Meter Transfer Block from either an AMCC, manual input or other system(s). The AMCC generates the Meter Transfer Block file that is transferred to the MDM/R. The MDM/R will process the files through a series of processes as outlined in the table below.

Type	Description	Pass	Fail
Syntactic Check	The structure of the file is validated against the appropriate file format for the specific AMCC.	• Acknowledgement back to LDC or AMI Operator. • Continue Processing Data.	• The LDC or AMI Operator is notified of rejected data records flagged as invalid.
Semantic Check	The content of the file is checked for validity and to determine whether a power outage, power restoration, or meter rollover has occurred.	• Continue Processing Data • Power outage, restoration, and meter rollovers are flagged	• The LDC or AMI Operator is notified of rejected data records flagged as invalid
Other Meter Read Data Loading Services			
Application of CT/PT Multiplier	Interval consumption data is multiplied by the CT/PT Multiplier set for each SDP through the synchronization process. Register reads are stored "as received" and no multiplier is applied		
Calculation of Interval Consumption from Register Reads	In the event that the AMCC only delivers register reads, the MDM/R calculates the corresponding interval consumption data prior to loading data into the Meter Data Database. Interval consumption data is stored at the same granularity of the Meter Read data as received from the AMCC (e.g. Meter Read data received at 5-minute intervals will be stored as 12 values). The register reads are also stored. The CT/PT Multiplier is applied when creating the associated interval consumption data. Register reads are stored "as received" and no multiplier is applied.		
Treatment of Missing Reads and Zero Reads	Zero reads are stored as an actual Meter Read of zero. Missing reads are detected by the MDM/R, stored as zero and flagged as 'No-Data' but may be estimated during VEE.		

Table 2-1 Pre-VEE Processes

2.3.2 Meter Read Data Transmission

The following sections describe the sets of data that may be transmitted from the various AMCC technologies to the MDM/R. These data sets are defined as Meter Transfer Blocks. Also described is the application of message validation and estimation services to the Meter Read Block as used by the MDM/R for validation and estimation.

"**Meter Transfer Block**" is a set of data transferred from an AMCC (or other system) to the MDM/R relating to Meter Read data for a specific SDP. A Meter Transfer Block is a set of interval consumption data with a register reading at the end of the set of interval data (see Figure 2-1), or a set of interval register reads for a number of contiguous intervals (see Figure 2-2).

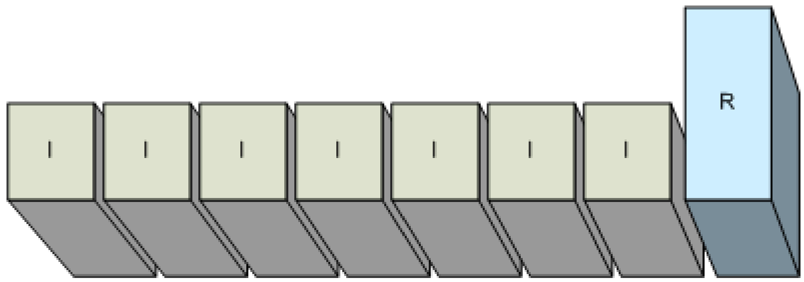

Figure 2-1 Cumulative Interval Consumption with a Stop Register Read

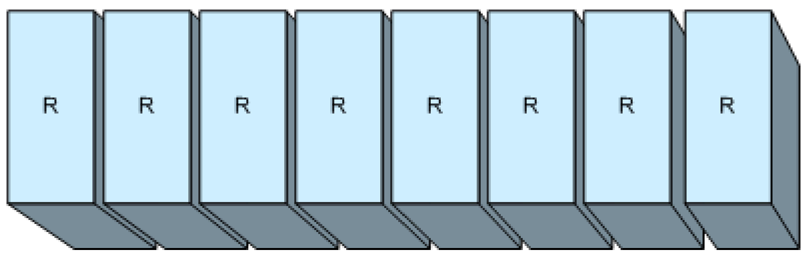

Figure 2-2 Register Reads For Each Interval

"**Meter Read Block**" is used by the MDM/R for validation and estimation purposes. Certain validation and estimation functions are based on acting upon a set of contiguous intervals bounded by a start register read and a stop register read. In some instances a Meter Read Block (see Figure 2-3) may span two Meter Transfer Blocks. For a Meter Transfer Block consisting of interval consumption data with a register reading at the end of a set of interval consumption data, the start register read for the Meter Read Block will be the immediately preceding (contiguous) stop register read.

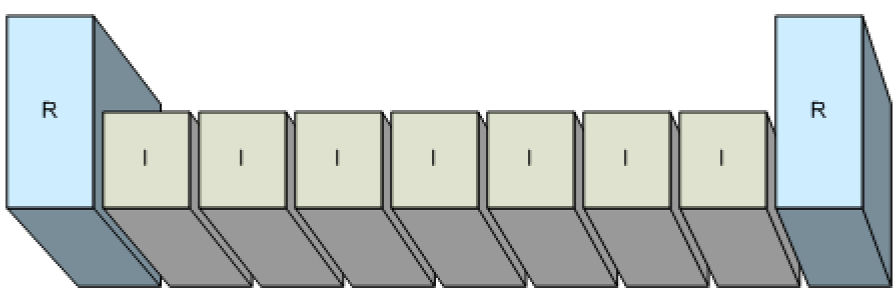

Figure 2-3 Interval Consumption with Start and Stop Register Reads

A Meter Transfer Block may be transmitted comprised of a stop register read only, with no associated interval consumption (see Figure 2-4). Such register read transmissions will be stored in the Meter

Data Database but will not trigger any validation algorithm or estimation algorithm for the estimation of the missing intervals.

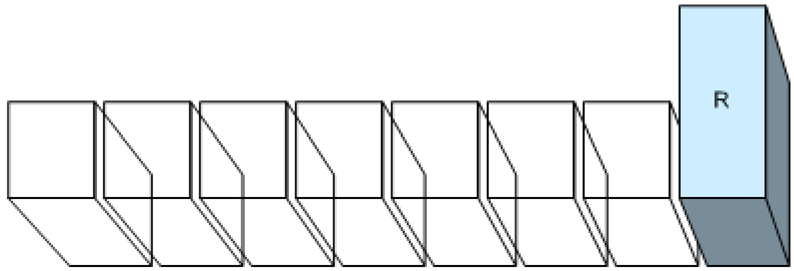

Figure 2-4 Stop Register Read Only, with No Interval Consumption

In Figure 2-5 the start register read (on the left) and subsequent interval consumption (below in grey) are stored in the MDM/R. Interval flags check; Maximum Demand Check, and Spike Check will be performed and if estimation is called for by the VEE Service, estimation will be attempted. The Sum Check will not be performed on the initial Meter Transfer Block. The new Meter Transfer Block contains a stop register read (on the right) but no interval consumption data. As with Figure 2-4 this register read transmission will be stored in the Meter Data Database but will not trigger any validation algorithm or estimation algorithm for the estimation of the missing intervals.

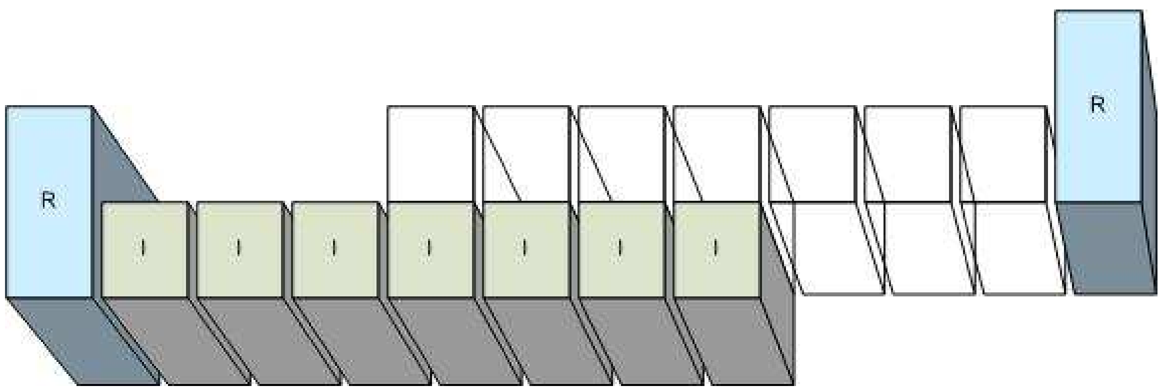

Figure 2-5 Meter Change with Incomplete Intervals

A Meter Transfer Block may be transmitted comprised of interval consumption only, with no associated stop register read (see Figure 2-6). Interval flags check; Maximum Demand Check, and Spike Check will be performed and if estimation is called for by the VEE Service, estimation will be attempted. The Sum Check will not be performed.

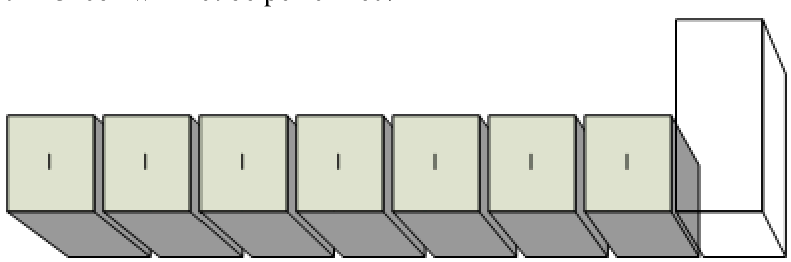

Figure 2-6 Interval Consumption with no Stop Register Read

In Figure 2-7 the stop and start register reads already exist in the MDM/R but with either no interval consumption data or perhaps estimated consumption data in between. The new Meter Transfer Block (below, grey) may provide, for example, edits to replace missing values or actual reads to replace estimated reads. This provides the LDC with the ability to send in edited meter reads or actual meter reads to fill in the gap between two register reads.

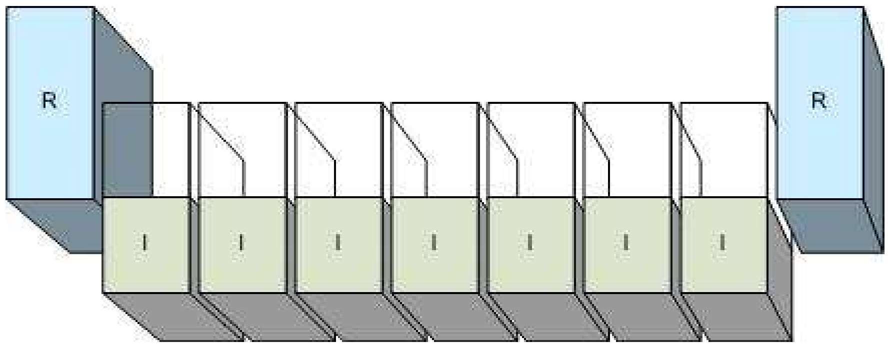

Figure 2-7 Edits Performed between Register Reads

2.3.3 Data Collection and VEE Reporting

The MDM/R provides daily reporting of the data collection processes and generates operational reports that detail the results. Complete specifications for these reports can be found in the MDM/R V1.0 Reports Technical Specifications. The data collection reports are as follows:

- DC01: Daily Read Status Report – providing a total count of meters for which data was received in the prior day segmented by AMCC type.
- DC02: Excessive Missing Reads Report – identifying meters that have failed to transmit register data for more than five days in a 10-day window.
- DC03: Interim Read Validation Failure Report – identifying *Meter Read* data files that have failed the incoming validation process for *Meter Read* data delivered to the MDM/R between midnight and the daily morning deadline for receipt of data for the prior *Daily Read Period* ‘N’.
- DC13: Final Read Validation Failure Report – identifying *Meter Read* data files that have failed the incoming validation process for *Meter Read* data delivered to the MDM/R during the entire previous day ‘N+1’.
- DC04: Missing Reads Detail Report – providing a listing of those meters for which data was not received for the most recent *Daily Read Period* ‘N’.
- DC05: Daily Data Collection Report – providing a total count of meters for which data was received in the prior day segmented by AMCC type and read age.

- DC06: Interim AMCC Data Collection Summary Exception Report – providing a summary of all exceptions encountered during the processing of *Meter Read* data files delivered to the MDM/R between midnight and the daily morning deadline for receipt of data for the prior *Daily Read Period* 'N'.
- DC16: Final AMCC Data Collection Summary Exception Report – providing a summary of all exceptions encountered during the processing of *Meter Read* data files delivered to the MDM/R during the entire previous day 'N+1'.
- DC07: Interim AMCC Data Collection Detailed Exception Report – providing a listing of all exceptions encountered during the processing of *Meter Read* data files delivered to the MDM/R between midnight and the daily morning deadline for receipt of data for the prior *Daily Read Period* 'N'.
- DC17: Final AMCC Data Collection Detailed Exception Report – providing a listing of all exceptions encountered during the processing of *Meter Read* data files delivered to the MDM/R during the entire previous day 'N+1'.

The MDM/R also provides daily reporting of the validation and estimation processes and generates operational reports that detail the results. Complete specifications for these reports can be found in the MDM/R V1.0 Reports Technical Specifications. The VEE reports are as follows:

- VE01: Interim Validation Failure Detail Report – providing a listing of all meters where Meter Transfer Block data has failed one or more of the validation checks for Meter Read data files delivered to the MDM/R between midnight and the daily morning deadline for receipt of data for the prior Daily Read Period 'N'.
- VE11: Final Validation Failure Detail Report – providing a listing of all meters where Meter Transfer Block data has failed one or more of the validation checks for Meter Read data files delivered to the MDM/R during the entire previous day 'N+1'.
- VE02: Interim Estimation Failure Detail Report – providing a listing of all meters where Meter Transfer Block data could not be estimated and the reason why for Meter Read data files delivered to the MDM/R between midnight and the daily morning deadline for receipt of data for the prior Daily Read Period 'N'.
- VE12: Final Estimation Failure Detail Report providing a listing of all meters where Meter Transfer Block data could not be estimated and the reason why for Meter Read data files delivered to the MDM/R during the entire previous day 'N+1'.
- VE03: Missing Interval Aging Report – providing a listing of those meters for which data was not received within the previous 3 calendar days.
- VE04: VEE Summary Report – providing summary number counts for the results of the validation; estimation; and verification/editing processes.

– End of Section –

3. Validation Standards

Validation is applied by the MDM/R in two ways: 1) data validation performed during loading of Meter Read data and 2) by the application of Daily Validation Services. Meter Read data validation during loading is applied to Meter Transfer Blocks received from all Smart Metering installations. The Daily Validation Services are applied in accordance with VEE Services defined for the type of consumer and metering installation. Daily Validation Services are configured to identify Meter Reads that fall outside of acceptable tolerance(s) and anomalies recorded by the meter.

The following sections describe the Meter Read data validation during loading, and the missing read checks.

- Validation Services for Residential or Small General Service Consumers, and
- Validation Services for Commercial and Industrial Consumers with the metering of demand with multiple channel metering.

3.1 Residential or Small General Service Consumers

Validation must be based on the characteristics of the data on hand. The list of checks and criteria itemized in the following sections shall be applied during validation of data collected by the AMI and transmitted to the MDM/R for consumers where the metering of demand is not required.

Validation will be performed for each Meter Transfer Block received from the AMI as part of Message Validation Services for residential or small general service consumers.

3.1.1 Message Validation Services

Validation Services are performed immediately upon completion of the Meter Read data load validation services for each applicable Meter Transfer Block. These services are performed on Meter Transfer Blocks received from the AMI or other systems. The validation checks performed on each Meter Transfer Block are referred to as message validation services.

Message validation service checks must be performed at the appropriate point in the data processing cycle of the MDM/R. Without strict adherence to the processing cycle, the validation service may fail resulting in invalid data. Some of these quality and completion checks must be performed by the AMCC and are described in section 2.2 of this document. Other validation checks within the MDM/R can be performed any time after data collection and before Billing Quantity generation. Billing Validation processes act upon the output from the Billing Quantity generation process and are described in Billing Validation Services section 6 of this document.

3.1.2 Overall Control

This parameter determines whether or not any validation and estimation is undertaken. If set to 'N' (No) then none of the following tests are undertaken. If the parameter is set to 'Y" (Yes), then all of the following tests that are enabled are undertaken.

Validation Check Sequence – Validation checks are performed in the following order:

1. Missing Intervals Check
2. Interval Flags Check
    a. Test Mode Check
    b. Pulse Overflow Check
    c. Time Change Check
    d. Meter Diagnostic Check
    e. Reverse Energy Check
3. Maximum Demand Check
4. Spike Check
5. Sum Check
6. Consecutive Zeros Check

3.1.3 Missing Intervals Check

The validation process identifies any gaps in interval consumption data within a Meter Transfer Block or between Meter Transfer Blocks and flags these gaps for Estimation or for verification/editing by the LDC based on the VEE Service parameter. Intervals for which a power outage is detected are not flagged as missing.

Power Outage Detection Within a Meter Transfer Block – This power outage detection algorithm identifies sections of missing intervals (i.e. 'NO_DATA' intervals) within a Meter Transfer Block that are part of a power outage. This algorithm for power outage detection is:

1. Within the Meter Transfer Block contiguous 'NO_DATA' intervals on either side of an "Outage" interval are flagged as 'POWER_OFF' and the 'NO_DATA' flag is cleared in these intervals.

2. An "Outage" interval is defined as:

    a. An interval with the 'POWER_OFF' flag set,
    OR

    b. An interval with the 'POWER_ON' flag set.

The "Outage" interval definition addresses data collection systems that may not set a power outage flag for an interval that contains a power restore event. A power restore event ('POWER_ON') in an interval implies that a power outage state ('POWER_OFF') was true at some point in the interval.

Power Outage Detection Between Meter Transfer Blocks – This power outage detection algorithm identifies sections of missing intervals between Meter Transfer Blocks that are part of a power outage. This algorithm for power outage detection is:

1. If the first interval of the of the current Meter Transfer block has a ‘POWER_ON’ flag set, get the interval record from the Meter Data Database for the last interval received prior to the start of the current Meter Transfer block

    a. If the last prior interval from the Meter Data Database has a ‘POWER-OFF’ flag set to ‘Y’, the section of missing intervals between Meter Transfer Blocks is part of a power outage. In this case set the ‘POWER_OFF’ flag to ‘Y’ and the interval value to ‘0’ for every missing interval between the last prior interval and the start of the current Meter Transfer Block.

    b. If the ‘POWER_OFF’ flag is not set for the last prior interval from the Meter Data Database, the section of missing intervals between Meter Transfer Blocks is NOT part of a power outage. In this case set the ‘NO_DATA’ flag to ‘Y’ for every missing interval between the last prior interval and the start of the current Meter Transfer Block.

3.1.4 Interval Flags Check

The Interval Flags Check handles all single-interval checks – checks that can be done without comparing intervals to other intervals. This includes the Missing Intervals Check described above as well as the validation checks described below.

Test Mode Check

The MDM/R inspects each interval for a Test Mode Flag. An interval with the Test Mode flag set fails validation only if the interval consumption is non-zero. If zero usage is recorded for the intervals in which the meter was in test mode, (i.e. meter was bypassed during testing) this data is considered valid.

Many meters will register 0 interval consumption while in test mode, thus if the meter records usage in test mode, the data does not represent actual Customer consumption.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

Pulse Overflow Check

The MDM/R inspects each interval for a Pulse Overflow Flag. A meter sets a Pulse Overflow flag when the energy consumption in an interval exceeds the range of the interval. This flag generally indicates a serious problem with the meter installation or the meter itself.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

Time Change Check

The MDM/R inspects each interval for a Time Change flag. The Time Change Flag indicates that the meter time was adjusted during the interval and the interval may be either shorter or longer than the specified interval at which the data is to be collected. The Time Change flag is maintained since intervals with Time Change are not used in Demand computations.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

Meter Diagnostic Check

The MDM/R inspects each interval for a Meter Reset Flag. The meter read interface adaptor maps the meter diagnostic flags from each individual type of device to the Meter Reset Flag a part of the Data Collection process. (Reference MDM/R Technical Interface Specifications, Meter Read Interface – for each AMI technology.)

Meter diagnostic error flags generally indicate a serious meter problem but may not necessarily indicate that the interval data is erroneous.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

Reverse Energy Check

The MDM/R inspects each interval for a Reverse Rotation Flag.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

3.1.5 Maximum Demand Check

The Maximum Demand Check is a conditional test enabled or disabled for each specific VEE Service by a “check” product parameter.

The MDM/R compares each interval consumption value against the Maximum Demand Value specified in the VEE Service parameter. Interval values represent fully scaled kWh quantities including the CT/PT Multiplier. The Maximum Demand Value is in fully scaled kW.

The Maximum Demand Value (in kW) is divided by the number of intervals per hour (intervals/hr) providing an energy equivalent Maximum Interval Value (in kWh per interval). Each interval consumption value (in kWh) is then compared to the Maximum Interval Value. Interval consumption values greater than the Maximum Interval Value will fail the Maximum Demand Check and the ‘Maximum Demand Action’ will be performed.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

3.1.6 Spike Check

The Spike Check is a conditional test enabled or disabled for each specific VEE Service by a “check” product parameter.

The MDM/R may perform a spike check on each Meter Transfer Block to identify intervals with high consumption relative to the surrounding intervals. The spike check validation is performed as follows:

- Identify the highest and Nth highest interval values where N is a VEE Service parameter. The default value for N is 3.
- If the highest interval has already failed a prior validation check, then spike check is not performed.
- If the highest interval is less than or equal to the configurable Spike Check threshold, skip the spike check. The Spike Check Threshold value is specified in kWh units. The Spike Check Threshold is set in the VEE Service parameters.
- If the Nth highest interval is less than or equal to the configurable Spike Check threshold, skip the spike check. Otherwise, subtract the Nth highest interval from the highest interval and divide by the Nth highest interval. The algorithm is as follows:
  (highest interval - Nth highest interval)/Nth highest interval)
- The MDM/R will apply the following pass/fail criteria to the data set:
  - If ((highest interval - Nth highest interval)/Nth highest interval) <= threshold (a configurable value) the interval passes the spike check.
  - If ((highest interval - Nth highest interval)/Nth highest interval) > threshold (a configurable value), the interval fails the spike check and the ‘Spike Check Action will be performed.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

3.1.7 Sum Check

The Sum Check is a conditional test enabled or disabled for each specific VEE Service by a “check” product parameter.

The Sum Check is performed after other validation checks and will only be performed if the Meter Transfer Block passes the Missing Intervals Check and all intervals have passed the previous validation tests flagged as validated (including “soft fail” intervals).

The MDM/R performs a sum check on the Meter Read Block. Should the absolute value of the Sum Check difference exceed the threshold this validation fails, and all interval records in the Meter Transfer Block will be flagged with the failure.

- The Meter Transfer Block must include at least one Register Read with a timestamp that is between the earliest and the latest interval timestamps in the Transfer block, i.e. the register read occurred during one of the intervals in the block. The Register Read with a timestamp at the end of a Meter Transfer Block is defined as the End Read. For the purposes of this

Sum Check the timestamp for the End Read is defined to be the reading at the end of the interval in which the reading was taken.

- Intermediate Register Read Conversion to End Read – A by-product of validation is that the Validator calculates the End Read from the Intermediate Register Read (IRR) value if all of the intervals between the two are valid. An Intermediate Register Read is defined as a Register Read with a timestamp that is between the earliest and the latest interval timestamps in the Transfer block. IRR conversion is performed using the following logic:
  IF:
  End Read is null AND Intermediate Register Read is null, do not perform Sum Check
  IF:
  End Read is null AND Intermediate Register Read is NOT null, calculate End Read from Intermediate Read and the sum of the valid intervals between the Intermediate register Read and the end of the Meter Transfer Block
  IF:
  End Read is not null, use End Read supplied as part of the Meter Transfer Block

- The Sum Check test will retrieve the most recent register reading and interval data from the Meter Data Database. This register read is defined as the Start Read and for the purposes of the Sum Check its timestamp is defined as the end of the interval in which if occurred.

- The Sum Check will subtract the Start Read from the End Read and compute the difference. If the value is negative the meter register has “rolled over” and 1 x 10^N will be added to the negative difference value where N is 4, 5 or 6 whichever will results in a positive value. The N reflects the number of meter register digits. For example add 100,000 to the negative difference value for a 5 dial meter.

- Sum Check failure is determined as follows. The sum of the interval consumption for intervals between the Start Read and End Read is divided by the CT/PT Multiplier and compared to the un-scaled register read difference. If the absolute value of the difference is greater than the Msg Sum Check Threshold, the ‘Msg Sum Check Action’ will be performed.

  |(∑ Interval values / CTPT Multiplier) **-** *(RR_Difference)| > Msg Sum Check Threshold*

  Note: When used with different CT/PT Multipliers, this algorithm tests that the tolerance is within the unscaled register readings. For example, if the CT/PT Multiplier was 80.0 and the Msg Sum Check Threshold was also 1.0, the Sum Check would test that the dial reading was within 1, meaning that the kWh was within 80.

- Meter Change and CT/PT Multiplier Change Detection – Because of the logic leading up to a Sum Check, it is not expected that a meter change event or CT/PT Multiplier change event would be the cause of a Sum Check failure. Nevertheless, if a sum check fails, the Validator does check for a meter change and/or CT/PT Multiplier value change event before reporting a sum check failure.
  A Sum Check failure is disregarded if a meter change or CT/PT Multiplier relationship change occurred anywhere in the time span delimited by a Start Read time and End Read time relative to the dataset being evaluated.

This test can be configured to validate with the failure flagged (i.e. soft failure), or require verification/editing. The ‘estimate’ action is not available for the Sum Check.

3.1.8 Extra-Message Checks

The Consecutive Zeros Check acts on data beyond the Meter Read data contained in a Meter Transfer Block.

Consecutive Zeroes Check

The Consecutive Zeros Check is a conditional test enabled or disabled for each specific VEE Service by a “check” product parameter.

A “Zero Interval” is defined as an interval where:

- Interval Value = 0
- NO_DATA is false (i.e. the 0 value is not the result of Missing Intervals)
- POWER_OFF is false
- POWER_ON is false

The MDM/R checks the Meter Transfer Block for consecutive zero values. The Consecutive Zeros Check is performed as follows:

IF there is at least one contiguous section of Zero Intervals in the dataset equal to or longer than ‘Consecutive Zeros Threshold’ THEN:

- Set ‘ZER’ bit in each Zero Interval FAIL_CODE
- Take action specified by ‘Consecutive Zeros Action’

IF the dataset contains one or more trailing Zero Intervals, query Meter Data Database for count of adjacent later Zero Intervals. If the count of adjacent later Zero Intervals + count of leading Zero Intervals is longer than ‘Consecutive Zeros Threshold’ (hours) THEN:

- Set ‘ZER’ bit in each leading Zero Interval FAIL_CODE
- Take action specified by ‘Consecutive Zeros Action’

IF the dataset contains one or more trailing Zero Intervals, query Meter Data Database for count of adjacent later Zero Intervals. If the count of adjacent later Zero Intervals + count of leading Zero Intervals is longer than ‘Consecutive Zeros Threshold’ (hours) THEN:

- Set ‘ZER’ bit in each trailing Zero Interval FAIL_CODE
- Take action specified by ‘Consecutive Zeros Action’

A Consecutive Zeros Check does not flag prior or later intervals that are discovered in the Meter Data Database to be part of a consecutive zeros failure.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimated, or require verification/editing.

3.2 Commercial and Industrial Consumers with metering of Demand (Multiple channel metering)

Data collection for Commercial & Industrial metering is expected to provide measurement data beyond the kWh data and associated register readings provided by metering used for Residential and Small General Service Customers where metering of demand is not required.

The MDM/R adaptors used for C&I Customers must be able to support kWh, kW, kVA, kVAh, kVAR, and kVARh along with associated registers.

3.2.1 Message Validation Services available to C&I Metering

Message validation services used for Residential and Small General Service Customers will also be available for use for C&I Customers.

3.2.2 Additions to Validation Services to Support C&I

The following validation check specific to C&I meters will be supported by the MDM/R.

kVARh Check

The kVARh check is performed to identify intervals where reactive load (kVARh) is present and active load (kWh) is not, indicating a suspicious usage pattern and possible meter malfunction. This check is only required when both kWh and kVARh are used for billing. If kVARh data is available but not used for billing, the check is optional. This check may be done on either consumption or pulse data, provided the data scaling is consistent throughout the period

– End of Section –

4. Estimation Standards

The MDM/R Estimation Standards applies a method that is operationally manageable and maintainable and is fair to Residential and Small General Service Customers where the metering of demand is not required, and Commercial and Industrial customers with the metering of demand is required.

The MDM/R Estimation Standard is consistent with the standard described in the "Ontario Energy Board, *Distribution System Code*, Last revised on June 27, 2007 (Originally Issued on July 14, 2000)" Section 5.3.2, specifically:

> "A distributor shall establish a VEE process according to local practice that is fair and reasonable and provides assurance that correct data is submitted to the settlement process."

This section provides a description of the application of the MDM/R Estimation Standards to:

- Residential or small general service consumers where the metering of demand is not required for single phase and three phase installations either self-contained or transformer type meters.
- Commercial and Industrial consumers where the metering of demand is required for single phase and three phase installations either self-contained or transformer type meters involving multiple channel and multiple data type metering.

4.1 Residential or Small General Service Customers

Estimation standards described in this section of the document refer to residential or small general service consumers where the metering of demand is not required. While other methods may arguably provide more accurate estimates the solution chosen uses historical data from a SDP to provide estimates that are representative of historical consumption at that SDP while providing computationally manageable overhead for 4.5 million meters or more.

4.1.1 Message Estimation Routines

Gaps or errors in interval data may be estimated by the MDM/R as they are identified in the validation process. Estimation for filling gaps between Meter Transfer Blocks is limited by the 'Max Estimation Days' parameter and gaps that exceed this value are not estimated. These estimations are performed on interval records marked as 'data requires estimation' by the validation processing.

Message estimation does not extend beyond the most recent Meter Transfer Block received. The Billing Validation process will call exception handling processes that will attempt use estimation to complete interval data that is missing at the end of a Billing Period. This includes extrapolation[1] of

[1] Billing Validation Extrapolation is a deferred delivery component – reference Component 27, MDM/R Change Request MCR No. 003.

interval data and associated reframing to generate complete Billing Quantities to the required End Date.

4.1.2 Linear Interpolation

If a section of data needing estimation is less than 'Max Interpolation Minutes' in length (e.g. 60 minutes) then this estimation uses linear interpolation to compute the interval values. If the 'Max Interpolation Minutes' is set to zero this method is not used.

Use point-to point linear interpolation to estimate the data using before and after endpoints, where:

1. Endpoints must be intervals with a validation status of 'validated' (VAL) including "soft fail" intervals. Intervals containing a power failure cannot be used as end points for linear interpolation.
2. If the section occurs in the middle of the Meter Transfer Block, the "first point" is the last valid interval before the section, and the "second point" is the first valid interval after the section.
3. If the section occurs at the beginning of the Meter Transfer Block, use the last interval from the historical data as the first point if the historical data is available and valid.

If before and after endpoints are not available, the interval(s) requiring linear interpolation will be flagged as PTS (i.e. no endpoints) with a validation status of 'needs verification or editing' (NVE).

4.1.3 Historic Estimation

If the section of data needing estimation is more than the 'Max Interpolation Minutes' and less than the 'Max Estimation Days' then estimation will be performed by averaging intervals from like day types to create a Daily Profile for the period to be estimated. A Daily Profile is a ranked list of valid reference days and the interval consumption value for each interval in the Daily Profile is simply the average of the interval values for the reference days.

If the section of data to be estimated exceeds 'Max Estimation Days' the intervals will be flagged as 'GAP' with a validation status of 'needs verification or editing' (NVE).

Use the average of selected reference days to estimate interval consumption data as follows:

- Only "validated" intervals can be used. Valid intervals are defined as those that have a validation status of VAL (including "soft fail" intervals and intervals that have been "verified" i.e. change method code 'VER'). Estimated intervals with a validation status of (EST) cannot be used.
- Data from days with a power failure cannot be used. Power failures can cause irregular usage patterns, resulting in data that is not typical for the Customer.
- The earliest possible reference date is calculated as the 'Oldest Like Day' before the section of data needing estimation.
- The latest possible reference date is calculated as either:

  a. The 'Newest Like Day' past the last day in the section of data needing estimation, or

b. The last day of the same billing cycle as the last day in the section of data needing estimation.

- Reference days are chosen to be of the like day type that are closest chronologically to the data needing estimation, regardless of seasonal crossover. Currently, like days can include days behind an account change.[2] This may include days after the day requiring estimation. When two potential like days are equidistant from the day requiring estimation the ‘before’ day is selected over the ‘after’ day.

There are two steps to the historic estimation process and these are described below:

1) Develop an average Daily Profile for each period to be estimated:

   a) Find the ‘Number Like Days’ (e.g. five) “same day of the week” reference days with valid data closest in time to each section of data needing estimation based on the rules listed in the previous section. If the section needing estimation is a holiday, the “same day of the week” is the closest Sunday. Calculate the average Daily Profile for each day type to be allocated using the selected reference days. If ‘Number Like Days’ same day of the week are not available, calculate the average Daily Profile using fewer reference days. For example if the section of data to be estimated is on a Tuesday and the ‘Number Like Days’ is five, select the five closest Tuesdays. If five Tuesdays are not available select four, if not then three, then two, then one.

   b) If no “same days of the week” reference days are available, look for the ‘Number Like Days’ “like” days that are closest chronologically to the section of data needing estimation. For example, if the intervals needing estimation are on Tuesday, use Monday, Wednesday, and Thursday. Only use weekdays with weekdays; only use weekends with weekends; use only Sundays or holidays with holidays. Calculate the average Daily Profile using up to ‘Number Like Days’ reference days (e.g. from one to five as available).

   c) If there is no valid ”same day of the week” or “like” reference days and ‘Use Class Load Profile” is set to “N”, the data may not be estimated and is flagged as NLK (NO_LIKE_DAYS) with a validation status of ‘needs verification or editing (NVE).

2) Use the average Daily Profile to estimate the usage data:

   The estimated value for each interval is simply the average interval value from the calculated Daily Profile. The average interval value from the Daily Profile is considered “raw estimated data” and is subject to Register Read scaling if the ‘Register Allocation’ parameter is set to ‘Y’ for the VEE Service.

The MDM/R will normalize the representative profile so that the consumption for the Daily Read Period is the same as for the daily read profile to be estimated. The profile could at some future point also be normalized for weather factors but weather factors will not be supported unless directed by the Ontario Energy Board.

Note that this method does not assume that the historical days are a good match for the profile of the Meter Read Block being estimated and implicitly assumes that no large changes in consumption behavior have occurred. The technique generates estimates that are typical of recent behavior as opposed to trying to match historical usage to the profile of the Meter Read Block being estimated.

[2] Account Specific Historical Information Algorithm is a deferred delivery component – reference Component 35, MDM/R Change Request MCR No. 013.

4.1.4 Class Load Profile

The MDM/R supports estimation using a single specified Class Profile for each VEE Service. These Class Profiles may be applied optionally to each VEE Service. The MDM/R Administrator loads the Class Load Profiles into the appropriate interval channels in the MDM/R. One Class Load Profile channel for each VEE Service is defined.

Setting the 'Use Class Profile' parameter to "Y" enables Class Load Profile estimation. It can then be used in two situations:

- The most common intended use case of Class Load Profile estimation is as a fallback estimation option for intervals that cannot be historically estimated because of NO_LIKE_DAYS. The historical estimation algorithm will set a flag on a dataset if an interval has a NO_LIKE_DAYS failure. After the dataset has been fully processed by the historical estimation algorithm, the flag is checked, and if it is set, the ClassLoadProfiler is called to estimate all intervals in the dataset that have NO_LIKE_DAYS failures.

- Alternatively, Class Load Profile can be configured to be used instead of historical estimation, by setting the 'Number Like Days' parameter to '0'. In this case, all sections of NE (needs estimation) intervals in a dataset that are NOT linear interpolation are estimated using Class Load Profile.

Class Load Profile estimation consists of two steps described below.

1. Initialization. At the level of the section of data needing estimation, a Class Profile is initialized using the channel reference specified by the 'Class Profile Channel' parameter for the VEE Service associated with interval data being estimated; and the Start Time and End Time of the section of data needing estimation.

   a. The Class Profile is loaded for a given time period. Class Profiles are always loaded in 24-hour midnight-to-midnight time chunks (to set up for subsequent Average Daily Usage scaling). A section of data needing estimation that contains less than a full day of data will trigger a full day of Class Profile data that covers the dataset time period. A section of data needing estimation that contains intervals that span more than one day will trigger multiple days of Class Profile data to be loaded to cover all the days represented in the dataset.

   b. If the Class Profile is successfully loaded (all expected Class Profile intervals are found in the database), an attempt is made to scale the Class Profile interval values using the **Average Daily Usage** of the interval channel. The scaler sums up the interval data values in the class profile and divides by the number of days in the class profile to obtain the Average Profile Daily Usage in kWh per day. The Average Daily Usage is then obtained for the interval channel (see algorithm description below). The scaling factor is then calculated as:

      scalingFactor = Average Daily Usage / Average Profile Daily Usage

   c. If a scaling factor is successfully calculated, each interval of the "raw class profile interval data" is scaled as:

      scaledIntervalValue = rawIntervalValue * scalingFactor

2. For each interval in the section of data needing estimation obtain the estimated interval from the ClassLoadProfiler, and set the change method code based on whether the Class Profile has been scaled:

   If scaled, change method set to ‘Class Load Profile, scaled with ADU’ (ESE)

   If not scaled, change method set to ‘Class Load Profile, unscaled’ (ESD)

The **Average Daily Usage** (ADU) for the interval channel is obtained by querying the Meter Data Database for register reads, and calculating the Average Daily Usage using the first two register reads that meet the criteria for use as endpoints in the ADU calculation.

Register reads are queried over the time period delimited by the ”Class Profile ADU Newest Read” (# of days) after the End Time of the section of data needing estimation, and going backwards through the ”Class Profile ADU Oldest Read” (# of days) prior to the Start Time of the section of data needing estimation.

Beginning with the most recent register read and working backwards in time, the list is searched for the first pair of register read values (designated as RR1 at RR1Time; RR2 at RR2Time) that meet the following criteria:

- The register reads must be separated by at least ”Class Profile ADU Min Days” full days, and
- Both register reads must have been obtained from the same meter with the same active CT/PT Multiplier value, and
- Neither of the register reads can be estimated (ESTIMATED_METHOD must be NULL).[3]

If there is a Meter or CT/PT Multiplier change between RR1Time and RR2Time, the earlier register read of the pair is re-designated as RR2 and a search is performed for an earlier register read (RR1) that meets the criteria above within time period delimited by the ”Class Profile ADU Newest Read” and the ”Class Profile ADU Oldest Read”.

If a valid register read pair is NOT obtained by this search, the Average Daily Usage cannot be calculated and the Class Profile is not scaled.

If a valid register read pair is obtained, they are first run through the Dial Rollover algorithm to adjust for possible dial rollover between the readings, and the Average Daily Usage (ADU) in kWh per day is calculated as follows:

ADU = (((RR2 – RR1)*CTPT Multiplier) * (seconds-per-day)) / (RR2Time-RR1Time)

Loading Class Profile Data – The MDM/R Administrator loads the Class Profile data into the appropriate interval channels in the MDM/R. One Class Profile channel for each VEE Service is defined. The Class Profile data is maintained in an Interval Data channel. The standard class profile is a 60 Minute Interval Data, kWh channel. Class Profile interval data must be provided in advance of any period that is to be estimated by the Class Load Profile estimation process. This means that

[3] Estimation of Register Reads is not performed by the MDM/R.

the interval data must be provided for several weeks or months into the future. Generally a Class Profile is available for a full year.

4.1.5 Register Read Scaling

Register Read Scaling is applied to sections of intervals after they have been populated with raw estimated data using either the historical or class load profile estimation methods. Before scaling, each section of estimated intervals is first checked to determine if a meter change has occurred during the section. If so, the section is divided into meter-specific sections and each meter-specific section is scaled separately. If a meter change is detected, the algorithm checks for CT/PT Multiplier changes within the dataset time period, and the sections belonging to the different meters are scaled separately using appropriate CT/PT Multiplier values. If there is a gap between the two meter relationships, the estimated intervals in that gap are left unscaled.

Historic estimation and Class Load Profile estimation will operate with and without register reads. The VEE Service parameter “Register Allocation” determines if the register reads will be used to scale the “raw estimated data” from historical estimation or the “raw class profile interval data” from Class Load Profile estimation. When register reads are available before and after the gap being estimated and ‘Register Allocation’ is set to “Y”, the estimated interval values will be adjusted so that the sum of the intervals (actual and estimated) between the register reads is equal to the difference in register reads.

Intervals estimated using historical estimation with register read scaling are recorded in the Meter Data Database with a validation status of ‘estimated’ (EST) and a change method code ESC.

Intervals estimated using Class Load Profile estimation with register read scaling are recorded in the Meter Data Database with a validation status of ‘estimated’ (EST) and a change method code ESF.

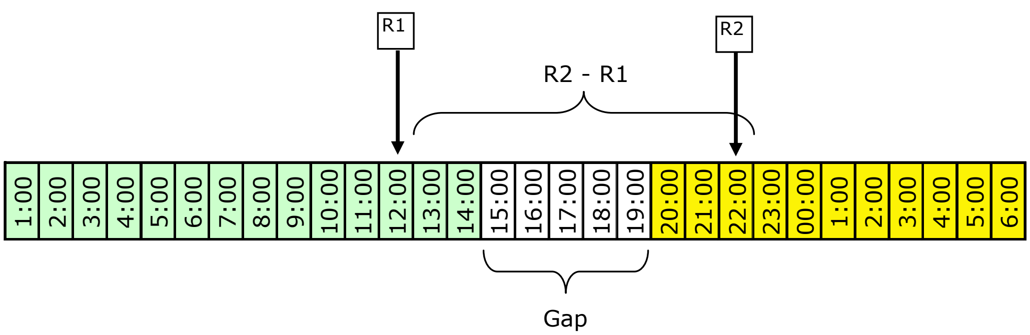

Figure 4-1 Estimation with Register Reads

As shown in Figure 4-1 register reads used in estimations are deemed to have occurred at the end of the interval in which they occurred. This assumption allows register reads to be used regardless of their alignment to the Meter Transfer Block or an interval boundary.

Although the AMCC interface requires that interval data is always accompanied by a register read, should register reads not be available on both sides of the gap being estimated or if ‘Register Allocation’ is set to “N” the ”raw estimated data” are not adjusted and are used as the estimate.

Intervals estimated using historical estimation without register read scaling are recorded in the Meter Data Database with a validation status of ‘estimated’ (EST) and a change method code ESB.

Intervals estimated using Class Load Profile estimation without register read scaling are recorded in the Meter Data Database with a validation status of ‘estimated’ (EST) and a change method code ESD.

4.2 Commercial and Industrial Consumers with metering of Demand (Multiple channel metering)

4.2.1 Message Estimation Services available to C&I Metering

The estimation algorithms used for C&I metering must require that all channels be present for estimation. In the event that one of more channels, but not all channels, are present for the same time interval, the estimation should fail. In effect, all non-register channels must be estimated simultaneously and in concert of each other. The absence of a single channel implies a serious meter failure and must be able to be configured for manual verification.

Message estimation services used for Residential and Small General Service Customers will also be available and applied to all channels for C&I metering and will include:

- Linear Interpolation, and
- Historic Estimation

Class Load Profile estimation is not proposed or expected to be required as the profiles for individual installations will vary drastically from location to location.

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5. Editing Guidelines

The MDM/R provides a Graphical User Interface (GUI) for performing manual verification and editing on Meter Read data. Upon notification of Meter Read data that Needs Verification/ Editing, the LDC will use the GUI to perform such verification or editing.

The OEB has provided some guidance for editing as described in the November 9, 2004 *Ontario Energy Board Smart Meter Implementation Plan, Draft Report of the Board For Comment*. Specifically:

> "When meter data is adjusted during the estimating process, there is always some risk that the estimated value will differ from actual consumption. Every effort must be made to ensure each estimate reflects accrual consumption to the extent possible. And to the extent possible, the risk of error should be born by the distributor."

The above principle may be applied by each LDC when editing meter read data.

5.1 Residential or Small General Service Customers

5.1.1 Manual Editing and Verification

Where actual interval consumption data is not available and automated estimation processes have not been successful, the LDC may be required to manually inspect and approve interval consumption data or to manually edit the values. The flowchart in Figure 5-1 describes this process.

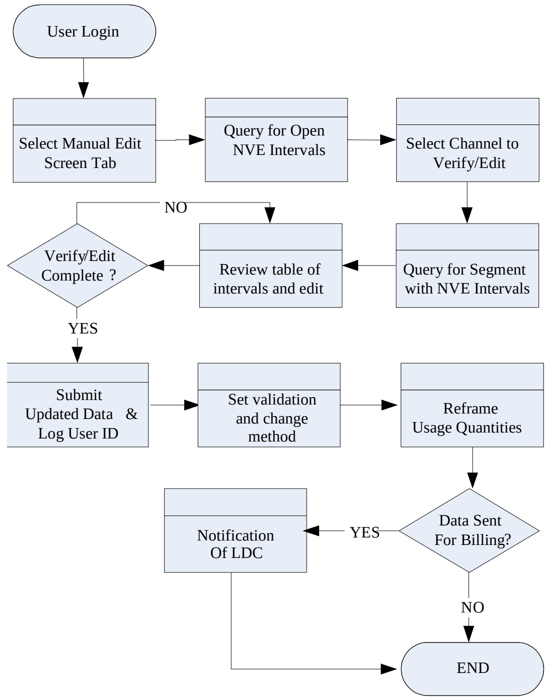

Figure 5-1 Manual Verification and Editing Flow

Locating Channels for Manual Editing

When validation checks result in interval consumption data being marked as data Needs Verification/Editing (NVE) the process automatically creates a record which contains the start and end times of the intervals that need manual verification and/or editing. An LDC user with appropriate permissions may generate a list of all such records and navigate to the interval channels that require attention.

Verifying or Editing Intervals

The LDC user may change interval consumption values in the GUI. When completed, the user submits the updated interval consumption data set. If the interval consumption data value is not changed the records are simply marked with validation status of Validated (VAL) and change method of Verified. If the interval consumption data values were changed (edited) they are marked with Validation Status set to Estimated (EST) and change method set to Edited (EDT). Intervals that are verified or edited in this process are updated in the Meter Data Database. The previous interval consumption data records are moved to the Prior Version table to maintain interval history.

Updating Billing Quantities After Editing

Channels that have been manually verified or edited in this process will be automatically reframed in order to update or complete the values in the Meter Data Database Usage table. Reframing is triggered as the interval consumption data version is updated. The LDC is notified where Billing Quantities have already been sent to the LDC based on prior interval consumption data versions.

5.2 Commercial and Industrial Consumers with Metering of Demand (Multiple channel metering)

5.2.1 Editing Support for C&I Metering

The editing functionality for meter data received from C&I metering must support the editing of all channel data (e.g.: kW, kVA, kVAR, kVAh and kVARh) simultaneously on the same screen.

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6. Billing Validation Services

Billing Validation takes place as Billing Quantities are assembled for delivery to the LDC or its agent as defined by the Data Delivery Service. Billing Validation is configured as part of the overall configuration of a Data Delivery Service including association with each VEE Service.

Billing Validations are performed on the data prior to producing Billing Quantity data. The Billing Validation process includes performing a sum check on the Billing Quantities over the period for which Billing Quantities are being provided.

The Billing Validation process will call exception handling processes that will attempt to use estimation to complete interval data that is missing during the Billing Period. This includes extrapolation[4] of interval data and associated reframing to generate complete billing quantities to the required End Date of the billing period. The extrapolation capability will be implemented consistent with the recommendation of the members of the SMSIP Joint Working Groups.

The Check Sum validation on Billing Quantity data will be performed by the MDM/R. SDPs identified as having this flag will be reported to the LDC to investigate and resolve.

6.1 Residential or Small General Service Customers

6.1.1 Billing Validation Sum Check

Prior to delivery of Billing Quantities for each SDP, the MDM/R performs the billing period validations. The Billing Validation Sum Check is configured as part of the Data Delivery Service parameters including association with a VEE Service. The MDM/R will perform the following billing validation tests once per billing request, as the Billing Quantities are prepared for export.

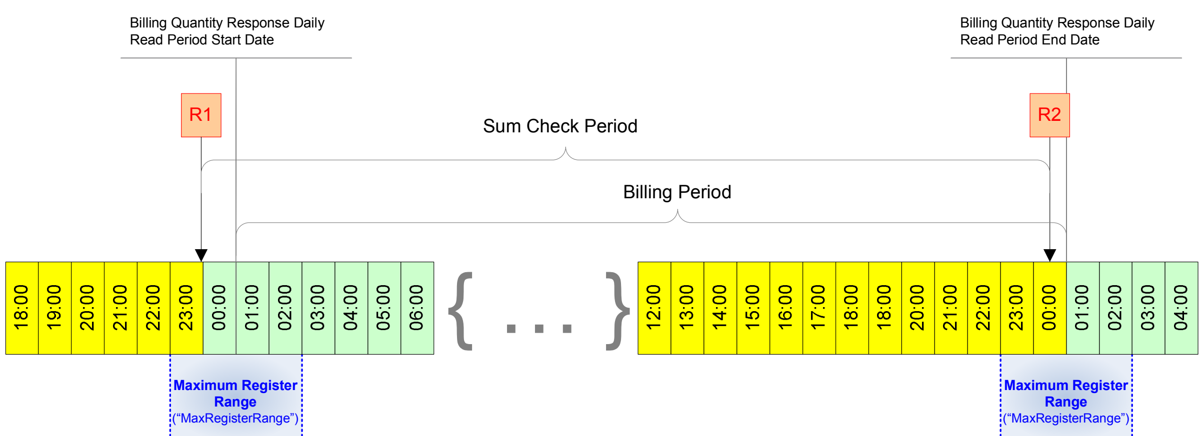

Figure 6-1 Billing Validation Sum Check on Billing Period

[4] Ibid Footnote No. 1.

The Billing Validation Sum Check is performed by comparing the total consumption of the Billing Quantity Response with the difference between the register read values nearest to the start and end points of the billing period as shown in Figure 6-1. Discrepancies may be the result of inaccuracies in manual meter data verification or editing activities.

The Billing Validation Sum Check accounts for the meter multiplier and applicable CT and VT ratios assigned to the SDP through synchronization (CT/PT Multiplier attribute) and meter register rollover and meter changes (using the First and Last Meter register readings taken at the time of the meter change and communicated through the synchronization process). The Billing Validation Sum Check requires two register readings. The first must be within 'MaxRegisterRange' hours of the Start of the billing period, the second within 'MaxRegisterRange' hours of the End of the billing period. If these register values are not available the Billing Validation Sum Check may be marked as a Billing Validation Sum Check failure or Billing Validation Sum Check skipped.

If the difference calculated above is greater than the 'ThresholdValue' for the VEE Service the Billing Validation Sum Check has failed.

The Billing Validation Sum Check 'ThresholdValue' is set specifically for the Data Delivery Service associated with each VEE Service. The threshold value above which the Billing Validation Sum Check fails may be expressed for each Data Delivery Service as one of:

1. 'Ratio' – the Sum Check is determined by comparing the absolute value of the total Billing Quantity consumption subtracted from the register reads difference divided by the register read difference to an allowable ratio i.e. the 'ThresholdValue', or
2. 'Value' – the Sum Check is determined by comparing the absolute value of the total Billing Quantity consumption subtracted from the register reads difference to a maximum kWh value i.e. the 'ThresholdValue'.

The register read difference (RR2 – RR1) is determined by RR2Time within the 'MaxRegisterRange of the Billing Quantity Response End Date and RR1Time within the 'MaxRegisterRange' of the Billing Quantity Response Start Date.

The threshold value when using the threshold type 'Ratio' is expected to be set at or below the error permitted under the dispute provisions of the Electricity and Gas Inspection Regulations. When using the threshold type 'Value' the threshold value is expected to be the maximum value of one interval period in kWh.

The Billing Validation Sum Check process accounts for CT/PT Multiplier when comparing the difference between the register read values and the total consumption of the Billing Quantity Response.

Billing Quantities for SDPs that fail the Billing Validation Sum Check may still be reported but the record will be flagged with the Billing Validation Sum Check failure code, alternatively the Billing Quantities may be nullified and the record(s) reported with the Billing Validation Sum Check failure code. The Billing Validation Sum Check is performed as soon as the billing process acquires complete data for the billing period in order to provide the LDC the opportunity to address sum check failures prior to the close of the billing window as defined by the 'LatestReportDays' parameter of the Billing Quantity process.

6.2 Commercial and Industrial Consumers with Metering of Demand (Multiple channel metering)

Billing validation services used for Residential and Small General Service Customers will also be available for use for C&I Customers.

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7. VEE Services

7.1 Overview of Message Validation and Estimation

Figure 7-1 illustrates the high-level flow of the message validation and message estimation processes. The initial step in the process is to determine the VEE Service that is to be used for the Meter Transfer Block. The process flow is then as follows:

1) Message Validation Checks - Interval consumption data in the Meter Transfer Block is checked against the criteria defined in the VEE Service parameters. Each interval within the Meter Transfer Block is assigned an outcome. The four outcomes supported are:
    a) Validated – the consumption in the interval passed all tests and is acceptable for billing and recorded with a validation status of ‘validated’ (VAL) in the Meter Data Database.
    b) Validate/Flag – the consumption in the interval has failed some validations but is acceptable for billing – these are soft validation failures. This data is flagged as having failed validations and recorded with a validation status of ‘validated’ (VAL) in the Meter Data Database. Soft validation failures are recorded as flag and failure codes on each interval record.
    c) Estimate – the consumption in the interval is incomplete or has failed validation, this data is passed on for automated estimation. This information will be recorded with a validation status of ‘needs estimation’ (NE) in the Meter Data Database but will not be made available for billing purposes until estimation is completed. These are hard validation failures.
    d) Verify/Edit – the consumption in the interval that is incomplete or has failed validation checks configured for manual verification or editing, this data is recorded with a validation ststus of ‘needs verification or edit’ (NVE) in the Meter Data Database pending manual processing. This information will not be made available for billing purposes until verification and editing is completed. These are hard validation failures.
2) Message Estimation Routines – Interval consumption data that has failed validation as incomplete (e.g. missing intervals) or having failed validation tests configured for estimation may be estimated according to processes defined by the VEE Service parameters. Register reads are not estimated. Estimated interval consumption data is then recorded with a validation status of ‘estimated’ (EST) in the Meter Data Database and flagged with a Change Method code indicating the type of estimation performed. Estimated interval consumption data is available for framing and the production of Billing Quantities.
3) Manual Verification or Edit – Consumption values for intervals that requires manual intervention is recorded with a validation status of ‘needs verification or edit’ (NVE) in the Meter Data Database. This data remains in this state and is not usable for billing until manual verifications or edits have been completed.
4) Interval consumption data for which the VEE Service is “No Validation” is recorded with a validation status of ‘not validated’ (NV) in the Meter Data Database and made available for billing.
5) Validated data; validated/flagged data; estimated data; verified or edited data, and ‘not validated’ data is available for daily Framing and the production of Billing Quantities.

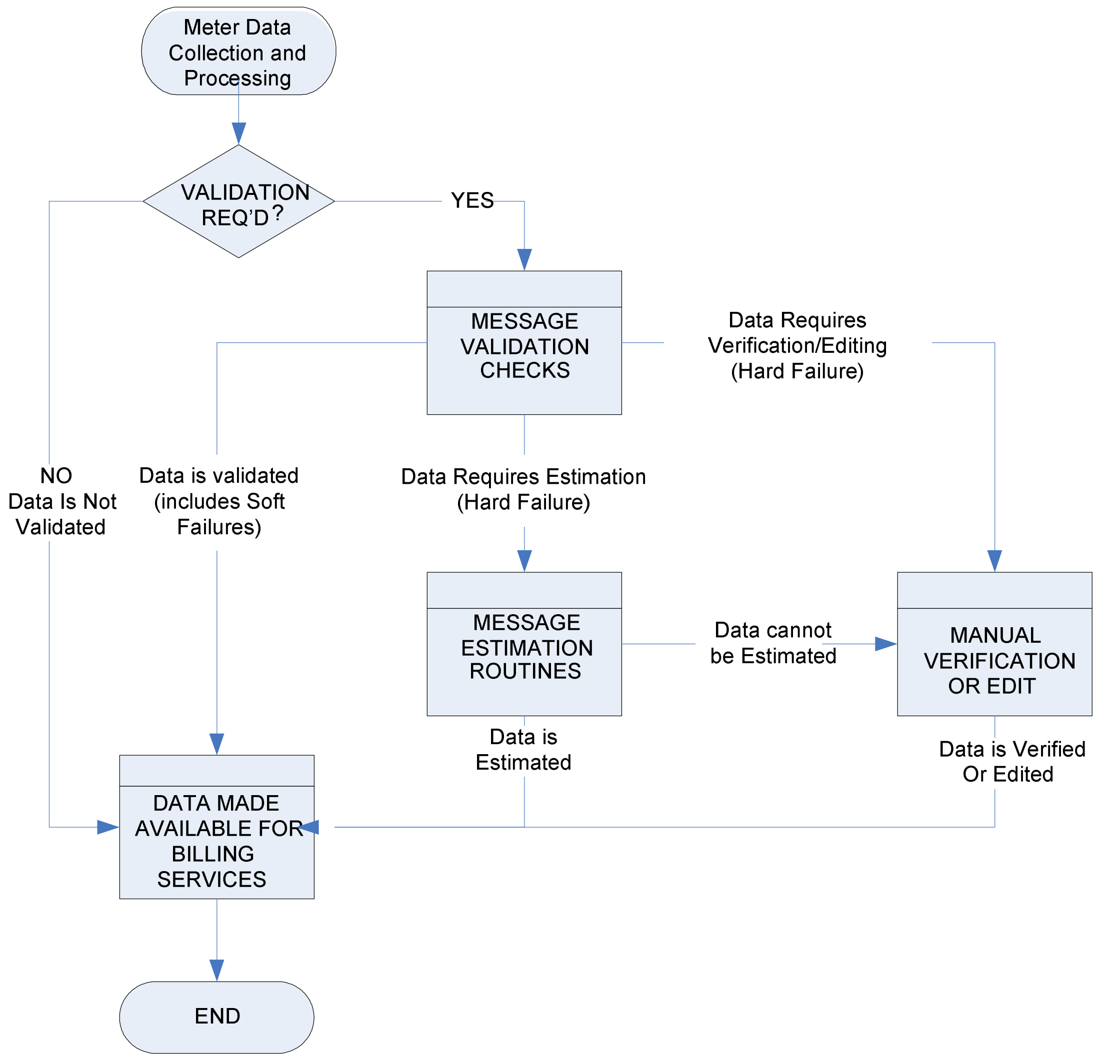

Figure 7-1 VEE Sequence as Meter Transfer Block is Received

7.1.1 Message Validation Checks

Table 7-1 below provides the parameters and descriptions for the message validation checks that are undertaken against each Meter Transfer Block. The columns in the table have the following meanings:

- **Validation Checks –** the nature of the validation test or check
- **Parameter –** the parameter that is set when the VEE Service is configured
- **Valid Value** – the allowable values of the parameter. For parameters labeled as 'Action' these are the values available for configuration to set the action when the validation check is deemed to have failed.

- **Description** – description of the parameter.

For each of the validation checks where an action is taken (as noted in the Parameter column in Table 7-1) one possible outcome is available based upon the configuration value chosen. Up to three configurable values may be available:

- **Validate/Flag –** Upon validation test failure interval consumption data is acceptable for billing. This data is flagged as having failed validations and stored in the Meter Data Database. These soft validation failures are recorded and reported to the LDC.
- **Estimate –** Upon validation test failure interval consumption data will not be made available for billing. This data is passed on for automated Estimation. These failures are recorded and reported to the LDC.
- **Verify/Edit –** Upon validation test failure interval consumption data will not be made available for billing. This data requires manual verification or editing and is saved in the Meter Data Database for manual processing. These failures are recorded and reported to the LDC.

All validation checks are undertaken for each interval, i.e. the process does not stop on encountering the first failure.

Validation Checks	Parameter	Valid Value	Description
Overall Control	Validation Enabled	Y/N	Indicates whether any validation or estimating is to be performed. If ‘Y’ validation is enabled If ‘N’ validation is disabled
Interval Flags Check			
Missing Intervals	Missing Intervals Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken for missing intervals. Flagged in the Meter Data Database as ‘NO_DATA’ and displayed in the GUI as ‘Y’ in the ‘NoData’ field.
Test Mode	Test Mode Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on reporting of a test mode condition by the AMCC. Flagged in the Meter Data Database as ‘TEST_MODE’ and displayed in the GUI as ‘Y’ in the ‘TestMode’ field.
Pulse Overflow	Pulse Overflow Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on reporting of a pulse overflow condition by the AMCC. Flagged in the Meter Data Database as ‘PULSE_OVERFLOW’ and displayed in the GUI as ‘Y’ in the ‘Overflow’ field.

Validation Checks	Parameter	Valid Value	Description
Time Change	Time Change Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on reporting of a time change by the AMCC. Flagged in the Meter Data Database as ‘TIME_CHANGE’ and displayed in the GUI as ‘Y’ in the ‘TimeChg’ field.
Meter Diagnostic	Meter Reset Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on reporting of a diagnostic error by the AMCC. Flagged in the Meter Data Database as ‘METER_RESET’ and displayed in the GUI as ‘Y’ in the ‘MtrDiagError’ field.
Reverse Energy	Reverse Rotation Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on reporting of reverse rotation by the AMCC. Flagged in the Meter Data Database as ‘REVERSE_ROTATION’ and displayed in the GUI as ‘Y’ in the ‘RevEnergy’ field
Calculation Based Checks			
Maximum Demand	Maximum Demand Check	Y/N	Indicates whether to perform the maximum demand check on each interval. If ‘Y’ maximum demand is enabled If ‘N’ maximum demand is disabled
	Maximum Demand Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken if maximum demand check fails. Upon failure stored in the Meter Data Database as a bit sum ‘FAIL_CODE’ decimal value = 64 and displayed in the GUI as a decimal sum under ‘FailCode’.
	Maximum Demand Value	Min: 0 Max: n/a Units: kW	Maximum demand value in kW for an interval
Spike Check	Spike Check	Y/N	Indicates whether to perform a spike check on the Meter Transfer Block. If ‘Y’ spike check is enabled If ‘N’ spike check is disabled
	Spike Check Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken if a spike check fails. Upon failure stored in the Meter Data Database as a bit sum ‘FAIL_CODE’ decimal value = 1 and displayed in the GUI as a decimal sum under ‘FailCode’.

Validation Checks	Parameter	Valid Value	Description
	Spike Check Threshold	Min: 0 Max: n/a Units: kWh	Minimum value in kWh of highest interval required to perform spike check
	Spike Check Ratio	Min: 0.0 Max: n/a	Maximum ratio of highest to Nth highest interval value to pass spike check.
	Second Peak Rank	Min: 2 Max: n/a	2,3,4, … 'n' the order of the interval value to use in the spike check ratio test – e.g. 2nd highest value, 3rd, 4th, etc.
Sum Check	Msg Sum Check	Y/N	Indicates whether to perform a sum check on the Meter Transfer Block. If 'Y' sum check is enabled If 'N' sum check is disabled
	Msg Sum Check Action	Validate/Flag Verify/Edit	Indicates action to be taken on failure of sum check in a Meter Transfer Block. Upon failure stored in the Meter Data Database as a bit sum 'FAIL_CODE' decimal value = 2 and displayed in the GUI as a decimal sum under 'FailCode'.
	Msg Sum Check Threshold	Min: 0 Max: n/a Units: kWh	The threshold value for a Meter Transfer Block in kWh for which the Sum Check test will fail. This is a value in kWh before the CT/PT Multiplier.
Extra-Message Checks			
Consecutive Zeros	Consecutive Zeros Check	Y/N	Indicates if the consecutive zeros check is to be performed If 'Y' consecutive zeros is enabled If 'N' consecutive zeros is disabled
	Consecutive Zeros Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on failure of consecutive zeros check. Upon failure flagged as 'ZER' on Reports VE01 and VE11.
	Consecutive Zeros Threshold	Number of intervals	Number of consecutive intervals with zeros allowed. NOTE: The specification of the threshold value as a number of intervals requires that a different VEE Service be defined for meters of different interval length.

Table 7-1 Message Validation Check Parameters and Descriptions

7.1.2 Message Estimation Routines

Gaps or errors in interval consumption data may be estimated by the MDM/R as they are identified in the validation process. Estimation for filling gaps between Meter Transfer Blocks is limited by the 'Max Estimation Days' parameter and gaps that exceed this value are not estimated.

Estimation does not extend beyond the most recent Meter Transfer Block received. The LDC is responsible for manually editing any Meter Read data where the Meter Transfer Blocks are not complete to the end of the billing period.

These estimations are performed on intervals recorded by the validation process with a validation status of 'NE' in the Meter Data Database.

Table 7-2 provides the parameters and descriptions for the message estimation that will be undertaken for intervals in each Meter Transfer Block that have been recorded as needing estimation. The columns in the table have the following meanings:

- **Estimation –** the nature of the estimation routine
- **Parameter –** the parameter that is set when the VEE Service is configured
- **Valid Value –** the allowable values of the parameter
- **Description –** description of the parameter.

Estimation Routine	Parameter	Valid Value	Description
Linear Interpolation	Max Interpolation Minutes	Min: 0 Max: n/a Units: minutes	Maximum number minutes that may be estimated using linear interpolation. Set to zero if linear interpolation is not allowed.
Overall Control	Max Estimation Days	Min: 0 Max: n/a Units: days	Maximum number of consecutive days that may be estimated either using Historic (Like Days) or Class Load Profile estimation.
	Register Allocation	Y/N	Determines if Historic estimations and/or Class Load Profile estimations are scaled using Register Reads at the start and end of the Meter Transfer Block.
Historic Estimation	Oldest Like Day	Min: 0 Max: n/a Units: days	Specifies the oldest day of historical data that may be used in historic estimation. The date established by this parameter is calculated in 24-hour increments relative to the Start Time of the first interval of a Meter Transfer Block needing estimation.

Estimation Routine	Parameter	Valid Value	Description
	Number Like Days	Min: 0 Max: n/a Units: days	Specifies the preferred (and maximum) number of reference days to use in calculating an historical estimation. Note: Setting this value to '0' effectively switches Historical estimation off. A '0' value is used when only Class Load Profile estimation is to be used for a particular VEE Service.
	Newest Like Day Method	'Newest Like Day' or 'Billing Cycle'	Provides for days after the day being estimated used as reference days. 'Newest Like Day' – use newer like days up to a 'Newest Like Day Limit' 'Billing Cycle' – use newer like days within a billing cycle.
	Newest Like Day Limit	Min: 0 Max: n/a Units: days	Used when 'Newest Like Day Method' is set to 'Newest Like Day'. Specifies the latest day of data that may be used in historical estimation. The date established by this parameter is calculated in 24-hour increments relative to the End Time of the last interval of a Meter Transfer Block needing estimation.
Class Load Profile	Use Class Profile	Y/N	Indicates if Class Load Profile estimation is to be performed. If 'Y' Class Load Profile is enabled If 'N' Class Load Profile is disabled
	Class Profile ADU Min Days	Min: 0 Max: n/a Units: days	Specifies the minimum separation between Register Reads used in calculating Average Daily Usage for Class Profile scaling
	Class Profile ADU Oldest Read	Min: 0 Max: n/a Units: days	Specifies the oldest day of Register Read data that may be used when calculating Average Daily Usage for Class Profile scaling
	Class Profile ADU Newest Read	Min: 0 Max: n/a Units: days	Specifies the latest day of Register Read data that may be used when calculating Average Daily Usage for Class Profile scaling
	Class Profile Channel	Channel Reference	If 'Use Class Profile' is set to "Y" this parameter must reference a valid channel containing reference interval data

Table 7-2 Message Estimation Routine Parameters and Descriptions

7.1.3 Validation and Estimation Outcomes

The MDM/R VEE Services generate meta-data relating to each specific interval consumption value and this meta-data is stored against interval records in the Meter Data Database. Table 7-3, Daily VEE Outcomes, lists the four validation statuses used to identify the state of an interval. Each state is further defined by the method used to modify an interval value and the validation test that failed. All Change Method Codes are recorded for each interval consumption value. Validation Failure Codes are set for all the VEE checks that fail for each interval.

Interval Validation Status	Change Method Codes	Validation Failure Code
NO VALIDATION (NV): No validation performed, data may be used as permitted.	**NULL**: Interval value not changed.	Not applicable
VALIDATED (VAL): Interval has been validated and is available for billing and other uses.	**NULL**: Interval value not changed. **VER**: Interval has been manually reviewed and verified for submission to billing.	Failure code(s) from validation failures as indicated in Table 7-1 NOTE: Failure code on validated interval is a Warning or Soft error
ESTIMATED (EST): Interval was estimated and is available for billing and other uses.	**ESA:** Interval value estimated using linear interpolation **ESB**: Interval value estimated using Historic estimation without Register Read scaling **ESC**: Interval value estimated using Historic estimation with Register Read scaling **ESD**: Interval value estimated using Class Load Profile estimation without scaling **ESE**: Interval value estimated using Class Load Profile estimation scaled using Average Daily Usage from register reads **ESF**: Interval value estimated using Class Load Profile estimation with Register Read scaling **ESG**: Interval value estimated using extrapolation **EDT:** Interval value has been manually edited. **EXT:** Interval value was estimated by an external system	Failure code(s) from validation failures as indicated in Table 7-1

NEEDS VERIFICATION/EDITING (NVE): Interval requires manual verification or editing and is not available for billing or other uses.	**NULL:** Null pending manual edit or verification then Validation Status changed to VAL or EST.	Failure code(s) from validation failures as indicated in Table 7-1

Table 7-3 VEE Outcomes

7.1.4 Billing Validation Sum Check

Table 7-4 provides the parameters and descriptions for the Billing Validation Sum Check that will be undertaken against each Billing Quantity Response. The columns in the table have the following meanings:

- **Validation Check** – the nature of the validation check
- **Parameter** – the parameter that is set when the VEE Service is configured
- **Valid Value** – the allowable values of the parameter
- **Description** – description of the parameter

Validation Check	Parameter	Valid Value	Description
Billing Validation Sum Check	BillingSumCheck	Y/N	Indicates whether to perform the Billing Validation Sum Check on the computed Billing Quantity. If 'Y' sum check is enabled If 'N' sum check is disabled
	BillingSumCheckFail Action	'Value' OR 'null'	Upon Billing Validation Sum Check failure: If set to 'Value' will provide Billing Quantity Response with computed values and error code If 'null' will provide Billing Quantity Response with 'null' values and error code
	MaxRegisterRange	Min: 0 Max: n/a Units: hours	Maximum period in hours to search for the register reads nearest the: Billing Quantity Response Daily Read Period Start Date and Billing Quantity Response Daily Read Period End Date

Validation Check	Parameter	Valid Value	Description
	NoRegRead Action	'Skip' OR 'Fail'	Action to take if register readings are not available. If 'Skip' Billing Validation Sum Check is not performed If 'Fail' Billing Validation Sum Check fails upon failure to find register reads
	Sync Mapping Code	Char (2) Specific usage: 01, 02, 03 … 30	The VEE Service to which the Data Delivery Service is to be associated.
	ThresholdType	'Ratio' OR 'Value'	The type of Billing Sum Check: If set to 'Ratio', a percentage based sum check is performed. If set to 'Value', a threshold based sum check is performed.
	ThresholdValue	Min: 0 Max: n/a Value of form: Number (1,3)	Threshold at which sum check passes or fails. If 'ThresholdType' is set to: 'Ratio' – then a percentage allowed for the sum check difference expressed as a ratio of the register read difference and the total Billing Quantity, e.g. 1% is 0.010 'Value' – then a value in kWh allowed for the actual sum check difference

Table 7-4 Billing Validation Sum Check Parameters and Description

7.2 VEE Services for Residential or Small General Service Customers

A VEE Service refers to a specific validation configuration in combination with a specific set(s) of estimation algorithms. A set of default VEE Services will be created that will enable Ontario LDCs to choose the VEE Services that are most appropriate for their consumers yet still provide a level of standardization across the province. The default VEE Services will be:

VEE Service, No Validation

This VEE Service does not perform any validation checks. This could be used when new SDPs are established in the MDM/R and the quality of data has not yet stabilized. This will allow for the collection of interval data in the MDM/R to be used for future estimation processes but will not create unnecessary notifications to the LDC until the data quality has stabilized. The SDPs using this VEE

Service will typically not be set to send Billing Quantities to the LDCs CIS system as the Meter Read data has not been validated.

VEE Service, No Estimation

This VEE Service could be used for any SDP where no automatic estimation is required. Any missing Meter Read data for a SDP using this VEE Service will require manual estimation or editing.

VEE Service, Residential

This VEE Service shall be used for the majority of residential consumers.

VEE Service, Residential – Electric Heat

This VEE Service can be used for residential electric heat consumers. These consumers typically display very unbalanced usage patterns between seasons.

VEE Service, Transformer Type

This VEE Service can be used for transformer type SDPs. These SDPs generally have a higher level of usage and the presence of Voltage and/or Current Transformers with a CT/PT Multiplier greater than 1 (one) require the need to have unique thresholds on some of the validation checks.

VEE Service, Small General Service

This VEE Service can be used for high usage consumers. This VEE Service has higher threshold values in the maximum demand validation check.

VEE Service, Seasonal

This VEE Service can be use for consumers that have no usage for extended periods of time.

Table 7-5 provides the configuration parameters applied for each of the default VEE Services described above. The configuration parameters for each default VEE Service are considered initial values. The efficacy of the configuration for each VEE Service will be demonstrated during testing and initial integrated operation of the MDM/R and AMI systems. The configuration for each VEE Service may be updated as the result of ongoing testing and operation of the Ontario Smart Metering System.

Parameter	No Validation	No Estimation	Residential	Residential – Electric Heat	Transformer Type	Small General Service	Seasonal
Sync Mapping Code	01	02	03	04	05	06	07
MESSAGE VALIDATION CHECKS							
Validation Enabled	N	Y	Y	Y	Y	Y	Y
Interval Flags Check							
Missing Intervals Action	N/A	Verify/Edit	Estimate	Estimate	Estimate	Estimate	Estimate
Test Mode Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Pulse Overflow Action	N/A	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit
Time Change Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Meter Reset Action	N/A	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit
Reverse Rotation Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Maximum Demand Check							
Maximum Demand Check	N/A	Y	Y	Y	Y	Y	Y
Maximum Demand Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Maximum Demand Value	N/A	50 kW	15 kW	25 kW	35 kW	50 kW	25 kW
Spike Check							
Spike Check	N/A	N	Y	Y	Y	Y	Y
Spike Check Action	N/A	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Spike Check Threshold	N/A	N/A	7.5 kWh	15 kWh	20 kWh	25 kWh	7.5 kWh
Spike Check Ratio	N/A	N/A	50	50	50	50	50
Second Peak Rank	N/A	N/A	3	3	3	3	3
Sum Check							
Msg Sum Check	N/A	Y	Y	Y	Y	Y	Y
Msg Sum Check Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Msg Sum Check Threshold	N/A	0.25 kWh	0.25 kWh	0.25 kWh	0.25 kWh	0.25 kWh	0.25 kWh
Consecutive Zeros Check							
Consecutive Zeros Check	N/A	Y	Y	Y	Y	Y	Y
Consecutive Zeros Threshold	N/A	336[5]	336	336	336	336	4380[6]
Consecutive Zeros Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag

[5] Based on a one (1) hour interval meter and 14 days

[6] Based on a one (1) hour interval meter and 6 months

Parameter	No Validation	No Estimation	Residential	Residential – Electric Heat	Transformer Type	Small General Service	Seasonal
Sync Mapping Code	01	02	03	04	05	06	07
MESSAGE ESTIMATION ROUTINES							
Max Interpolation Minutes	N/A	0	0	0	0	0	0
Overall Control – Historic Estimation and Class Load Profile Estimation							
Max Estimation Days	N/A	0	15	15	15	15	45
Register Allocation	N/A	N	Y	Y	Y	Y	Y
Historic Estimation							
Oldest Like Day	N/A	0	30	30	30	30	0
Number Like Days	N/A	0	5	5	5	5	0
Newest Like Day Method	N/A	Newest Like Day	Newest Like Day	Newest Like Day	Newest Like Day	Newest Like Day	Newest Like Day
Newest Like Day Limit	N/A	0	1	1	1	1	1
Class Load Profile Estimation							
Use Class Load Profiles	N	N	N	N	N	N	Y
Class Profile ADU Min Days	N/A	N/A	N/A	N/A	N/A	N/A	5
Class Profile ADU Oldest Day	N/A	N/A	N/A	N/A	N/A	N/A	30
Class Profile ADU Newest Day	N/A	N/A	N/A	N/A	N/A	N/A	1
Class Profile Channel	N/A	N/A	N/A	N/A	N/A	N/A	Internal Siebel Ref
BILLING VALIDATION SUM CHECK							
BillingSumCheck	N	N	Y	Y	Y	Y	Y
BillingSumCheckFail Action	N/A	N/A	Value	Value	Value	Value	Value
MaxRegisterRange	N/A	N/A	1	1	1	1	1
NoRegRead Action	N/A	N/A	Fail	Fail	Fail	Fail	Fail
Sync Mapping Code	01	02	03	04	05	06	07
ThresholdType	N/A	N/A	Ratio	Ratio	Ratio	Ratio	Ratio
ThresholdValue	N/A	N/A	0.010	0.010	0.005	0.005	0.010

Table 7-5 Default VEE Services Configuration

7.3 VEE Services for Commercial and Industrial Consumers with metering of Demand (Multiple channel metering)

VEE Services for C&I customers will be configured based on existing and additional validation, estimation and editing functionality developed for the MDM/R and after consultation with the SMSIP Working Group VEE Sub-Committee.

– End of Document –