AUTOMATED METER INFRASTRUCTURE WHITE PAPER

ISSUES, BARRIERS AND TECHNOLOGIES

FOR

SUSTAINABLE DEVELOPMENT TECHNOLOGY CANADA

By
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Executive Summary

This Report examines the state of technology development and market adoption of smart metering technology and provides an assessment of opportunities for strategic investment. To do so requires a clear definition of a smart meter as this term is used broadly in the industry. In the technological context, a *smart* device has resident or embedded intelligence to collect data and support or even execute a decision making process. With respect to smart metering, this term is really a misnomer as the smart meter is in essence a standard (typically electronic) revenue grade utility meter into which an electronic module has been embedded with the purpose of recording and communicating time-stamped consumption data automatically to a central data repository. As such, a functional system is more than a device installed at a user end-point. In its entirety, this system is generally referred to as “smart meter infrastructure (SMI)”, or more accurately, as Automated Metering Infrastructure (AMI) by the industry. The term smart meter will be used interchangeably with the term AMI throughout this document

As indicated, a smart meter is a generic term for a utility meter with an embedded electronic module, either retrofitted of factory installed. A complete system incorporates a module and a communication pathway over a public or private telecommunications network, linked to a central computer system incorporating a data repository or warehouse to organize, verify, store and format data primarily for utility billing purposes. The module embedded in the meter extracts data and attaches time meta-data to each “reading” (consumption, demand etc.). The module typically provides on-board memory (for data redundancy primarily) and includes a telecommunications card to transmit data over a variety of networks. More advanced systems can communicate bi-directionally, from central system to end-point, and vice versa. They are capable of initiating requests for data from the central system as well as detecting and communicating other parameters including meter tampering, power outages, and voltage fluctuations.

From the perspective of utility infrastructure, it is clear that the more sophisticated smart meter systems begin to cross the boundaries of automated meter reading systems and into the realm of utility SCADA (Supervisory Control and Data Acquisition) functionality; specialty software systems designed to monitor the performance and status of key points in the distribution system. This very issue is at the root of a complex debate over what functionality AMI needs to incorporate and how it can be leveraged for other utility operational benefits considering mass-deployment of AMI. As one of the primary cost drivers is the one-time visit to the end-premise meter (i.e. for installation), the characteristics of the end-point device are an important consideration.

Smart meters, and their inherent infrastructure represent a significant and rapidly evolving commercialized technology. There are many manufacturers of end-

point hardware in North America, several device-agnostic data management software solutions, and a variety of communications pathways available in both the public and private domains for the purposes of moving data and/or initiating some type of action.

The ramifications of implementing SMI for the energy sector (including utility, energy efficiency and demand management) are fundamentally industry-altering as they require new business processes, and interfaces to existing systems. SMI also enables many of the strategies for more efficient infrastructure utilization including time-based pricing, critical peak pricing, and detailed data collection for load research and system planning.

Sustainable Development Technology Canada (SDTC) is positioned to fund disruptive technologies that represent opportunities for paradigm-shifting industry operational models. In consideration of the complexities of real-time demand and supply of energy markets, it is difficult to defend a proposition that SMI technology by itself represents such an opportunity, particularly at the end point (customer premise). Rather, as both an enabling technology and a platform for consolidating functionality currently residing in stand-alone systems, SMI offers the opportunity to generate economies of integration that do represent efficiency gains.

If there is a strategic position for SDTC to take in this area, it is best described as an integration of technologies that accommodate two-way intelligent command and control of electricity use and the adoption of that functionality. In either case (stand-alone or integrated technologies), benefits related to emissions reductions are dependent upon factors beyond those immediately associated with technology development including pricing regimes, regulatory oversight, and market adoption. None of these are easily predicted and resolving technology challenges associated with integration may not settle these other issues. Projects that can demonstrate the technology integration and bring the various market actors together that may have a role to play in resolving these issues could be compelling. In particular, the role of local electric distribution companies is of considerable importance; any potential project would benefit from the presence of a local utility.

Background

Canada's electricity infrastructure is aging, built on technology approaching the end of its useful lifecycle. With much of this infrastructure requiring replacement, the market's interest in SMI is timely. Along with the need to upgrade technology, comes the opportunity to do so on a mass scale for economies in implementation. And along with the increasingly urgent need to address issues of supply, reliability, and spiraling demand, there is a critical opportunity to apply new technologies in the investment cycle that are on the cusp of market acceptance. This relates both to the nature of the technologies - their "readiness" for commercial application - and the greater expectations from the market.

Residential utility meters have never been a source of useful information to consumers partly due to their outdoor location and partly due to the consumer unfriendly means of displaying consumption (dials and numeric multipliers in particular). The meter has been a tool for billing at the *front end* of the cash register; it was never contemplated as a tool for the consumer. Many commercial businesses already have electronic interval meters since they are charged for peak demand and may otherwise contract for power or purchase power from the spot market (where such markets exist). In either case, time-based metering is a pre-requisite. The interest from residential customers in accessing the potential information is still somewhat unpredictable.

The market is also demanding greater efficiency, reliability, and quality in power delivery. Ever more, automated manufacturing incorporates power-sensitive computer-based systems and requires higher quality power. Formalized energy reduction and management processes are increasingly based on energy monitoring and management software applications, both of which are driven from data warehouses of detailed time-based consumption and power quality data for trending and analysis. While these systems are largely for "inside the building" energy management, there is a clear evolution of technology to acquire and consolidate data for a portfolio of facilities to provide a comprehensive picture of the energy consumption and make business and operational decisions that include energy as a criterion.

There are millions of smart meter end-points in North America installed over the last 15-20 years. The largest manufacturer claims an installed base of 40 million AMR devices, while the next largest competitors quote numbers in the range of 3-5 million end-point devices.

The utility sector has been slow to pursue this technology, likely because of its disparate regional regulatory policy, available communications infrastructure, integration costs, and issues of stranded assets. The latter being a particular concern as technology lifecycles continue to compress in the smart metering domain. Implementation of SMI to date has been more strategic, although a handful of jurisdictions have undertaken large-scale deployment. Internationally, the best-known project is the mass deployment of 30+ million meters in Italy over a period of about two years.

This paper sets out to assess the state and direction of SMI and related technology, trends in the industry from the utility perspective (in most jurisdictions, the meter resides on the balance sheet of the utility and is not "contestable"), and where opportunities may exist for SDTC to fund strategic investments in Canadian smart meter and ancillary technology innovation.

Ultimately, the existence of gaps between the capability of current technologies and market needs represents the strategic opportunity to make investments in new technology and that opportunity may well be related to innovations to deliver robust interoperability of devices and a broader array of applications to run on existing smart meter technology platforms. The more progressive smart metering vendors, aware that a single end-point solution is unlikely for a given customer, are evolving their solutions based on industry (open) standards for communication protocol, meter integration and data structure to ensure their products can be integrated with other end-point systems and not be excluded, due to proprietary technologies that make integration into larger systems an additional barrier to implementation.

One challenge for the industry is that the economics for upgrading the end-point meter lie in a one-time visit to the customer premise. The functionality installed will dictate the extent to which it can support the other elements of a comprehensive policy for sustainable energy use going forward, including the delivery of price signals and demand response applications.

This background provides essential context for the ensuing discussion regarding the complex issues of SMI, evolution, and investment. Economics, logistics, functionality, integration, and regulation weave a complex web of stakeholder challenges and benefits that are not easily resolved or de-constructed.

Section 1 of this document defines the categories of systems and then examines the marketplace to identify the current status of technology, the parallel paths of competing technology platforms, and an assessment of requirements from the user perspective.

Section 2 examines the market based barriers and issues, including regulatory mood, and barriers and challenges to technology development and implementation. It also considers experience in the U.S. (both regulated and de-regulated jurisdictions) and briefly considers the relevance of the large-scale implementation that occurred in Italy.

Section 3 considers the potential markets and provides a discussion of the various vendors that are operating in Canada including the Canadian Context. (Appendix A provides more detailed discussions of each vendor).

Section 4 provides an overview of barriers hindering widespread adoption. The focus of the discussion is the market, infrastructure, and policy barriers.

Section 5 examines the expected technology impacts, including the potential (electricity) savings that might occur as a result of deployment.

Section 6 examines the potential benefits, the opportunities for strategic investments, and also presents Sustainable Development Technology Canada's experience to date with Round 1 applications from this sector.

Section 7 is a summary of the salient points.

Appendices include a Glossary of Terms, a detailed examination of Vendors, and references that were accessed for the paper.

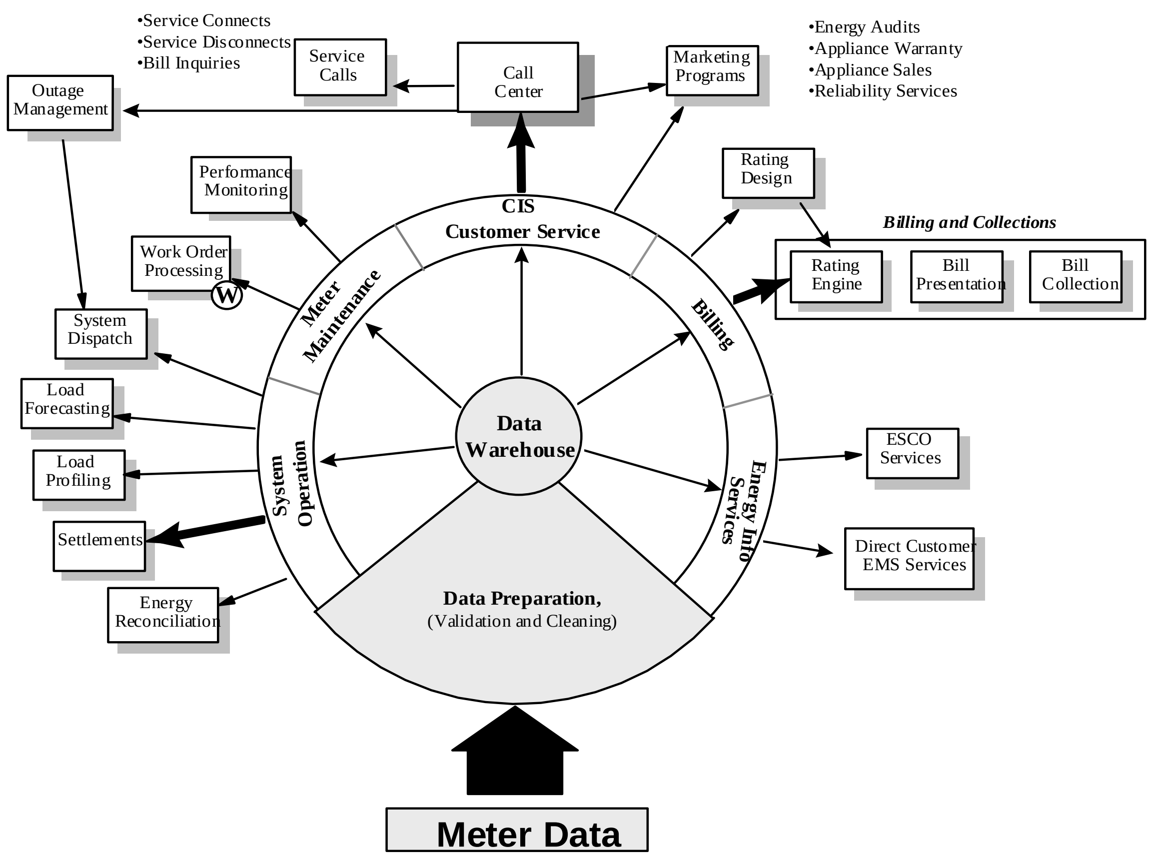
1. Situation Analysis

While California and Ontario continue to be the focus of the industry with respect to smart meter implementation on a large scale in North America, there have been somef regionalized efforts resulting in strategic installation of smart meters and related infrastructure. Internationally, a major smart meter installation was undertaken in Italy resulting in every customer receiving a new smart meter (see Section 2). This however, is atypical for how the market is evolving.

1.1 Categories

Interval metered customer demand and aggregated usage data is a common foundation for most electric utility back office, customer service, and system operating functions. Billing, outage management, forecasting, real-time dispatch, rate design, and many other utility functions depend upon some form of metered interval data. To be most effective, metering systems must be integrated and designed from the outset to support other utility functions (Figure 1).

Figure 1. Meter Data Applications Within a Traditional Utility[1]



[1] California Energy Commission

Traditionally, metering systems are viewed as the vehicle for collecting energy usage data to support a monthly billing function. Often referred to as the "utility cash register," a perspective that creates a focus on meter reading to support revenue requirements. It ignores the impact that metered data has on other aspects of utility operations. Treating metering and billing as a separate system, isolated from other utility operations, creates duplication of data and multiple systems with overlapping functionality, delayed access to information and overlapping unnecessary costs.

Two attributes determine how metered data is used to support the functions identified in Figure 1: (1) the time interval over which customer usage is measured; and (2) how long it takes to access (time frame) and retrieve measurement results.

Traditional billing, based on tiered rates, uses aggregated electrical energy retrieved over monthly billing cycles. Automated meter reading systems (AMR), that rely on meter readers using hand-held recorders or drive-by vans with short-distance remote reading capability, can easily support conventional billing requirements. However, outage management, dynamic tariffs, and many customer energy management functions often require usage interval data and data retrieval cycles measured in minutes, not the monthly cycle associated with traditional billing statements. Advanced metering infrastructure (AMI) with remote communication capability is necessary to support all of these functions. The important question is how to quantify the additional benefits and costs associated with AMI systems that are not necessarily billing related but provide much more fundamental functions such as preserving system reliability and improving customer service.

Meters used with AMR and AMI systems record the same usage information, sometimes over equivalent recording periods (e.g. once every 15 minutes). However, there are some important differences between the eventual capabilities of AMR and AMI systems:

1. AMI systems retain and make the detailed interval data available for other uses: AMR systems aggregate the detailed interval data into a either single 'running total' for the facility or into defined 'billing buckets' to support a particular rate.
2. AMI systems provide remote communication to support frequent (daily or on-demand) access to metered data: AMR provides limited communication that requires either on-site or near-site capability to access metered data.
3. AMI systems can support customer access to usage data independent of the billing process while AMR systems do not provide this capability.
4. AMI systems can be designed to support all utility functions, while conventional standard watt-hour meters and AMR systems cannot.

Earlier, it was noted that there are several components that comprise a smart metering system or AMI, and that AMI functionality crosses the boundaries of metering infrastructure into SCADA-type functionality. Communication, measurement, and control capabilities have a number of applications in utility operations including:

Smart Metering/AMI – such as end-point devices, one or two-way communication networks, data storage/management, asset management and integration tools.

Load Control – The remote control of energy consuming appliances and devices (residential and ICI) using end-point switches, one or two-way communication networks, and software based scheduling, command, and dispatching applications.

Smart Thermostats and Devices – the remote re-setting of HVAC set-points or intelligent devices that ramp up or down based on historical operating trends using similar control applications and controls.

Distribution Automation – SCADA-type functionality to detect power quality, outages, meter tampering, theft of power, and system diagnostics.

Distributed Generation – the evolution of DG on the grid requires similar dispatch, command, control and monitoring, and aggregation. Distributed generation, and demand response capacity is dispatched in response to pricing or other system signals for economical ? reasons?.

Combining these generic applications with a communications infrastructure delineates two key categories, one-way and two-way, with each communications infrastructure type having either high or low flow data capability. The major innovations that are occurring in the industry are around two-way command and control capability. Meters that simply tell the user how much load is observed without enabling control of that load represent the lowest rung on the smart meter ladder. At the other end are systems that read, monitor, communicate, and control usage, based on intelligent or pre-configured responses. (See Section 3.3 for a full discussion of leading edge developments).

The meter-to-cash process that results in the production of a customer utility bill based on interval data is the result of a lengthy chain of activities upstream. It includes data acquisition, validation, editing, storing (smart meter vs. smart network) formatting, and integration with a billing system. The biggest difference with existing manual meter reading processes is the frequency of data collection (bi-monthly for residential customers in general) and the absence of time-based consumption data.

With regards to interval metering, there are few large-scale interval based smart metering systems in operation that collect hourly data. In Ontario, where the market was designed as an hourly market, it was concluded through extensive consultation with industry stakeholders, that the infrastructure should match the market's operation model. It is generally accepted that if the system is required to support spot market participation of customers who choose critical peak pricing, and other structured time-based price plans, then collecting and storing hourly data will maximize the utilization of the data, the flexibility of future rates, programs, and other market mechanisms.

In Ontario, the Minister of Energy directed the Ontario Energy Board to develop an implementation plan for smart metering which would enable consumers to see a price signal, provide an economic incentive to reduce and/or shift energy consumption, and to ensure there were no infrastructure-related constraints to implementing a variety of price schemes including time-based and critical peak-pricing. Without smart metering systems, these plans cannot be implemented and existing blended or averaged rate structures invariably lead to some rate classes subsidizing others.

Clearly, the term *smart meter* has become a catch-all label for what really is a much more complex and interactive set of devices and systems. Technically, the smart meter is not a meter at all and the objective of this section is to define and distinguish among the categories of devices and systems that in aggregate create advanced meter infrastructure.

The Customer Premise Device

For clarity, the term "smart meter" is used to describe a telecommunications module that is connected to a conventional utility meter, be it electro-mechanical or electronic. That module, which records the meter readings and applies a time-stamp to it, is connected to a telecommunications pathway. The first deployments of automatic meter reading devices incorporated fairly standard telephone modems and were either polled by a head end system or reported-in based on a programmed schedule. Most modules now also have embedded memory (most manufacturers do provide "on-board" memory) to provide an element of redundancy for lost or corrupted data. Most module manufacturers attempt to ensure compatibility with the major meter manufacturers.

Recently, manufacturers began focusing on wireless communications, some utilizing unlicensed radio frequencies at 900 MHz, others moving up to the 2.4GHz band range. In early 2004, much focus was placed upon "short-hop" radio technology with the purpose of enabling "peer-to-peer" communication among end-point devices. One of the communication protocols that has moved rapidly to the forefront is termed in the industry as ZigBee, an open standards design based on a 7-layer stack architecture on which the functionality of the two physical and access layers defined by IEEE 802.15.4 (2003) functionally. It is a low powered, low GHz radio frequency transmission protocol ideally suited for *short-hop*, low bandwidth communication.

Communication among peer-to-peer devices creates a network or *mesh* through which data can be propagated from one end-point device to another and eventually reach a collection device equipped with Wide Area Network capability. Mesh networks are interesting for residential applications as they will propagate data around line-of-sight obstacles and have redundancy built in, finding multiple pathways to propagate data. They are-low powered and can sleep between transmissions, minimizing energy consumption and extending battery life of devices so equipped. Finally, as compared to a GSM or GPRS radios, they are a fraction of the cost and do not require network subscription except at the data collector. The model of multiple meters communicating to a regional data collector equipped with a WAN connection (wireless, network modem etc.) minimizes telecommunications charges and component costs.

The major alternative to the wireless mesh network for residential AMI communication is power line carrier technology, which is the basis for products manufactured by Echelon, DCSI, Cannon and others. Power line carrier communicates over electric power lines, most effectively on the secondary side of the transformer. Economically attractive, particularly in low population density areas, communicating this way is effective where the distance between adjacent meters is large (beyond the typical range of a ZigBee-type radio) and the number of meters on the secondary side of a given transformer is relatively high. One of the challenges for this technology however is its inability to maintain data integrity from the primary side of the transformer.

From an economic perspective, fewer meters per collector diminishes the cost effectiveness, implying the need for a higher ratio of collectors to meters. The ability to “hop” a transformer and propagate data with high integrity to the primary side would allow a single collector to acquire data from many more meters. In Europe, where homes typically have 60 Amp service, more homes can be served with a single transformer and therefore power line technology has had an economic advantage able to serve larger geographic areas with less installed components (an important consideration when examining large-scale implementations in Europe).

The final major sub-system of smart meter infrastructure is the meter data management system itself. Within it are a number of application layers for validating, storing, and formatting actual meter consumption data. Additionally these systems also serve as asset management systems for hardware tracking, installation, removal and re-installation to ensure that a communicating meter is actually attached to the right home for the account being billed. This is a critical functional element, as smart meter implementations are typically contemplated on a large scale to generate economies and the logistics of managing the field deployment require a central system for dispatching inventory (provisioning), commissioning regional collectors, and initializing the communication link between the meter, collector, and central system.

Table 1.1 identifies some of the high-value utility and customer applications and services that can be supported with an advanced metering AMI system. Implementing AMI creates benefits on its own, independent of the underlying tariff structure. The reader is encouraged to consider this table as part of any assessment of the various product offerings

Table 1.1. Comparing the Functional Capability of Various Metering Options

Application / Function	**Standard Watt Hour Meter**	Automated Meter Reading (drive-by)	Advanced Metering Infrastructure with Communications
Utility Functions			
a. Automated Meter Reading	NO	LIMITED	YES
b. Outage Detection	NO	NO	YES
c. Theft Detection	NO	LIMITED	YES
d. Load Survey	NO	LIMITED	YES
e. Customer Energy Profiles –for EE / DR Targeting	NO	NO	YES
Customer Functions			
a. Customer Rate Choice	NO	NO	YES
b. Customized Billing Date	NO	NO	YES
c. Energy Information	NO	NO	YES
d. Dynamic Tariffs	NO	NO	YES
d. Enhanced Billing	NO	NO	YES

Experience with telecommunications, financial, and transportation industries indicates that the cost savings and operational impacts attributed to SMI are probably only first order effects that reflect the most immediate and most easily attainable benefits. SMI-type technology applications may trigger a series of first, second, and third order effects which increase efficiency, demand for new products and services, and the formation of entirely new business ventures.

Electronic supermarket cash registers and bar codes provide a good example. Bar coding, product codes, and pricing information are now standardized and allow for real-time transactions. Previously, information was entered separately to support each function related to the product manufacturing, distribution, and sales process. Bar codes were originally developed to expedite checkout; the analogy to the current manual meter read is evident.

The supermarket industry initially resisted the move to electronic registers and bar codes because the value was not considered sufficient to offset the required investment. In other words, the reduction in ‘checkout costs’ (e.g. meter reading) was not considered sufficient to justify a move to a new technology. It soon became apparent that the same bar code used to support automated checkout, could also be used to automate the inventory function, which in turn found applications in purchasing, pricing, shrinkage analysis, automation of general accounting, and automatic order entry applications.

1.2 System Requirements vs. User Requirements

From the vendor perspective, the landscape is equally difficult to map. Is the technology leading to new applications, or is the market demanding new capabilities and thus driving innovation? Attempting to answer this question introduces development risks for solutions providers. It is not clear if new technology will be readily adopted in the marketplace or if incremental enhancements will be better received.

Recent examples illuminate the challenge. In 2005, Hydro One Networks in Ontario issued an RFP investigating the technology capabilities available in the market to meet a broad spectrum of functional requirements. These ranged from the simplest AMR systems to deliver interval consumption data to the most advanced solutions capable of full 2-way communication, interval data, load limiting, load disconnect, tamper detection, outage detection, broadband communications, wireless connectivity, power line connectivity, and even Wi-Max wireless broadband.

New infrastructure would require systems integration to existing data, billing, and customer systems as there is no large scale deployment of hourly interval data at the residential level. By virtue of geographic, topographic, and demographic criteria, more than one customer premise technology would be required to serve a territory, as would multiple communications platforms. Over 70 respondents submitted proposals for some combination of services, product or complete solutions, hardware, software, and data management services. As it turns out, the marketplace participants, particularly the hardware vendors, are all in a similar place in the technology evolution cycle and not all the functionality sought by Hydro One was actually available from any one provider.

In light of the above, an on-going debate continues as to how functionally rich a solution is required today, versus what functionality can be introduced on the same technology platform to meet future needs. The outcome of this debate lies largely in the information provided by the same manufacturers who share their product development plans but are not in a position to move forward without evidence of interest from the market; the classic “Catch 22” scenario.

1.2.1 Functionality

For the utility sector, the challenge is to define the requirements that will deliver the functionality required to meet the current system requirements, comply with existing regulatory requirements, and align with the emerging policy frameworks of today, with an understanding that even over the course of large-scale deployment period, there will be advances in product and functionality. It is highly unlikely that any implementation at a large scale that will result in a homogeneous population of field-installed devices, unless the LDC foregoes improved versions in the name of complete homogeneity.

In Ontario, where most of these issues are front and centre, LDCs are understandably sensitive to a prescriptive policy by the government. Issues abound related to who shall specify, procure, implement, and pay for smart meter infrastructure. Industry visionaries point out that the meter is the ubiquitous and vital connection to the home. The meter infrastructure, complete with its communications capabilities, represents tremendous opportunities to layer on additional applications beyond meter data management, and even beyond the LDCs service mandate.

1.2.2 Technology Convergence

There is also the issue of technology convergence. This is relevant because the second major debate relates to whether smart metering and demand response functionality should reside in a common customer premise device, utilizing a common communication pathway. This issue has provided another opportunity to polarize stakeholders. The market is seeing cycles of miniaturization where companies including Echelon and semi-conductor manufacturers are consolidating metering systems, memory, and related functionality to the chip level. The embedded intelligence in such devices can enable much of the functionality described above. With considerably more “real-estate” available under the glass arising from this miniaturization, additional micro-processor boards could be installed to enable demand response within the home, be it through power line carrier or wireless connectivity.

1.2.3 Horizontal Industry Application

The “potential” capabilities of this technology to provide connectivity and applications horizontally across industry sectors raises a new almost philosophical issue; If applications can be layered over the infrastructure for multi-utility uses (electricity, water and gas), mobile workforce management, asset management, broadband services, emergency response, -- to name a few -- on whose balance sheet should this ‘portal’ meter asset rightfully reside? The LDCs in Ontario opposed any move to remove the meter asset from its rate base as the meter was at the core of its business and “meter-to-cash” processes.

It has been proposed that for the very reasons listed above, a province-wide wireless communications network be deployed by a third party to provide a common telecommunications platform upon which interested parties could subscribe to deliver their applications. Such an approach, while ratcheting the issues to a higher level of societal benefit, introduced a new series of debates not the least of which regards the competitive nature of such a network with existing licensed public telecommunications carriers. The interests of the parties are further complicated as Hydro One Networks Inc. itself has in its asset base some 23,000 km of fibre-optic cable traversing the province primarily along its high voltage transmission lines which it currently leases to among others, the major licensed telecommunications carriers.

1.2.4 Smart Metering Infrastructure – Mission Critical?

This network-related debate escalated another issue regarding the integrity, continuity of service, and security of such an infrastructure. Should in fact utility meter data applications be delivered over the public communications networks at all? If deemed to be mission-critical, then such infrastructure would be beyond the abilities of public systems to deliver against the service level of LDC requirements. The ability of the public telecommunications infrastructure to continually move large volumes of data in small packet sizes at relatively slow speed and low bandwidth does not represent a technological challenge. The issue is data integrity, continuity of service, and security.

1.2.5 Open Standards and Interoperability

The mid-eighties saw the commercialization of micro-processor based controls which quickly displaced hard-wired control panels for all manner of equipment as well as in centralized plant control systems.

For the original equipment manufacturers, their controllers quickly became the new marketing battleground for differentiating their products from competition. This corporate marketing war distracted these companies from what became a key issue in distributed control systems (DCS); the ability to tie together disparate pieces of equipment into a plant control system. In fact, while manufacturers were boasting the limitless capability of micro-processor based controls, they were also extremely secretive about the communications protocols they had invested in to operate their controllers.

As consulting engineers began to ask OEMs for these protocols to build out the DCS, it became readily apparent that the proprietary protocols of the myriad plant OEM equipment required translations, replication, and significant systems engineering to deliver an integrated plant control system. What started as the source of competitive advantage was quickly transformed as the focus on the technology distracted from the customer’s ultimate objective. This forced OEMs to revisit the source of competitive advantage of their products, realizing that interoperability would be the critical element to maximize market share. Today, there are a handful of industry-standard communication protocols for industrial and commercial applications. They include familiar monikers like Modbus, BACnet, and Lonworks.

There are many parallels that can be drawn to the world of smart meter infrastructure and in many ways the stakes are higher. The one-time opportunity to visit millions of customer premises to exchange a device in a mass deployment scenario was previously alluded to. The cost implications of subsequent change-outs due to incompatibility are onerous. Devices deployed in the field that are based on industry recognized protocols really support the "plug and play" model as new functionality is added while new devices are deployed that can be easily added to existing networks. Interoperability has become a fundamental criterion to minimizing systems integration effort and *strandability* of premise devices. For example, a meter equipped with a mesh radio system using the 802.15.4 (Zigbee) protocol to propagate data to adjacent meters could also be leveraged with load control devices installed at a later date as part of different programs in the home with minimal network implications. And because there are myriad incremental functional elements that smart meter infrastructure could support, this approach minimizes the constraints for future functionality and disruptive costs.

Many OEMs have raised counter arguments that as long as integration can be achieved with minimal effort (through sharing protocol information) that interoperability can also be achieved. While this may be legitimate in principle, when applied to potentially millions of devices, building out the device network on a homogeneous, open standards communication platform will ensure minimal network issues, maximum reliability, and security. The issue here is not raised to debate one protocol over another but rather to emphasize the importance of using industry standards wherever possible in the construction of this infrastructure.

2. Policy and Regulatory Environments

In Canada, policy and regulatory activities in Ontario are setting the tone for the industry. This relates to Ontario's place on the electricity "de-regulation continuum". Arguably, Ontario is further along than any other jurisdiction in Canada. Ontario also has a utility distribution system that is somewhat unique in Canada, the use of regulated Local Distribution Companies (LDCs) (most municipally owned), to deliver electricity. LDCs purchase power from suppliers, deliver it to the customer, and (usually) own the metering infrastructure. Their interest (or lack thereof) and role in the smart meter debate is critical.

To date, most LDCs have been somewhat slow to adopt the new technologies in spite of the aging infrastructure challenges identified above. Understandably, LDCs have a variety of concerns, not the least of which is the role of the provincial government vis-à-vis mandating (or not) the use of smart metering. This is an important consideration as it ultimately affects who funds the technology, and within whose asset base it resides; the ratepayer or the taxpayer. LDCs by nature can be conservative regarding the adoption of new technologies as safety and reliability are paramount to their mandate. In addition, LDCs earn a return based upon the size and nature of both their asset and operational base. This can represent a conflict with the conservation theme. In combination, these two factors represent significant barriers to the adoption of any new technology, but especially one that can affect load shape.

From the perspective of the LDCs, this suite of technologies represents operational opportunities, <u>not</u> customer enabling technologies. As such, their interest typically relates to improving their own operational functionality. In Ontario, new regulatory direction, under the umbrella of Conservation and Demand Management (CDM), is encouraging the LDC community to undertake demand management activities on the behalf of their customers. There are a variety of traditional energy efficiency offerings that have been launched, as well as a number of new load displacement and smart meter initiatives.

Concurrently, Ontario LDCs have been instructed by the Minister of Energy to defer any implementation of smart metering beyond proof-of-capability and pilot projects in anticipation of clear direction as to the scope and structure of the province's smart meter implementation plan, leaving them in a "wait and see" mode. This raises concern over what to install in the on-going requirements of the business to service new construction and meter replacements in existing homes, and who will pay for these assets should they become stranded as a result of impending new regulation.

Given the somewhat conflicting directions, it seems unlikely that a significant deployment will occur in the short term. The Ontario Ministry of Energy has also delayed the implementation date of the time-based element of the Regulated

Price Plan (RPP) on the basis that without clarity on the path and timing for smart metering, incurring expenses to bill on time-based measures would be unjustified.

2.1 North American and International Experience

In the U.S., approximately 40 LDCs have experimented with real-time metering over the last two decades. Few programs have managed to gather and/or maintain substantial customer participation. Nearly all of the programs have been voluntary programs and many were adopted by vertically integrated, regulated LDCs that operate in states without retail competition.

Notionally, it is anticipated that deregulation of the electricity industry may affect the roll-out of AMI with de-regulated jurisdictions having a greater likelihood of experiencing growth in the market (greater price flexibility and less reliance of price subsidies). In the U.S., 25 states have deregulated their electricity markets, including:

Arizona	Michigan	Oregon
Arkansas	Montana	Pennsylvania
California	Nevada	Rhode Island
Connecticut	New Hampshire	Texas
Delaware	New Jersey	Vermont
Illinois	New Mexico	Virginia
Maine	New York	Washington
Maryland	Ohio	West Virginia
Massachusetts		

All of the deregulated states above, with the exception of Nevada and New Mexico, offer programs related to real-time meters to a portion of their customer base. The majority of these are voluntary programs.

Real-Time Meter Program Details

Accurate data or information on numbers of participants with real-time meters is difficult to find. The most detailed level of information available is from California, which shows participation in these programs to be 23,342 commercial and institutional customers with a smaller number of residential participants.

Given the size of the potential markets, this level of participation is exceptionally small and could be more accurately characterized as pilot program participants. The residential sector in particular has not seen significant penetration of advanced metering systems. A number of states do offer utility-based programs that are designed to encourage voluntary participation in incentive based programs.

The California experience revealed an average cost per meter installation was approximately $1,500, including the communications software and access to a web-portal that enables customers to gain access to their pervious day's hourly energy usage and demand profile. Each meter is estimated to save 26 kilowatts in peak electric demand. However, given the cost, voluntary participation in a program is likely to remain limited.

An examination of the California experience indicated that 40% of surveyed customers responded that they had used their web portal (or Energy Manager) to take each of these following actions:

- Shift energy usage away from On-peak hours
- Shift energy demand away from On-peak hours
- Reduce overall energy usage
- Reduce energy demand

This supports the notion that the program is having the desired effect. The (limited) pilot project experience in Ontario also supports this notion (see Section 5).

Competitive or deregulated environments with numerous providers may encourage a more diverse mix of metering and communication systems than a single provider system would. It is also likely that competitive environments are subject to higher unit costs from lower installation volumes, lower densities over which to pay back fixed communication equipment costs, and higher customer switching/turnover rates. With fewer meter units per sale, vendor overheads and selling expenses are also higher.

There are no specific types of metering systems that are inherently better suited to regulated versus unregulated environments. Appropriate equipment type is determined, in either case, by the volume of meters to be installed, the density of installations within an area, the needs of both the customer and service provider, and finally, the viability of the competitive market.

The largest implementation of smart meters occurred in Italy. The Italian example provides some insights into what enablers might be needed to assist in large scale roll-out of the technology. The main advantage Italy had that supported the roll-out is homogeneity; a single utility and a common vision around the role of the electricity distribution utility and the telecommunications platform. In spite of the apparent success, the mass roll-out was not without some problems, including incorrect billing, faulty meters, and communications failures. Given the size of the project, some challenges can be expected, however risk-averse investors point to the problems that resulted from the Italian experience with smart meters as proof that there are concerns and issues.

In Ontario, there are approximately 90 electric LDCs – a potential barrier in and of itself. These LDCs favour private communications platforms. The public carriers (Rogers Communications, Telus, Bell Mobility, etc) are clearly proponents of their own systems and foregoing the duplication of infrastructure. LDCs are expected to want to create and use their own platforms while intense lobbying can be expected from the communications industry. All of this adds to a long list of issues that will have to be considered.

The Ontario Government has been unable to resolve these myriad issues to the satisfaction of the majority of stakeholders to date. In an attempt to conclude the disputes on numerous levels, it proposed that the procurement, implementation and management of province-wide smart meter infrastructure be conducted under the purview of the government. Such an approach would likely require an agency to manage the specification and RFP process, project management, and an operating company to act as the *smart meter entity* as specified in the recently Tabled Ontario Bill 21. Thus far, this entity has not been created.

2.2 Energy Pricing

The role of price, and more importantly, price structures, is vital. Hourly pricing can be sent to users and support peak reduction and distributed capacity. In Canada, hourly pricing for residential customers from LDCs is rare, if implemented at all, however the regulations in Ontario provide for any customer to participate in the spot market. Hourly pricing for larger (>200 kW) customers is more common.

A recent example in the Pacific Northwest underscores the importance of prices and the nature of market response. The Puget Sound Energy (PSE) Personal Energy Manager Time-Of-Use Program was a large-scale pilot project that included the deployment of wireless residential smart meter technology in conjunction with a time-based pricing structure from the PSE. While the program did not use hourly data to calculate hourly consumption, it did introduce a time-based rate to encourage participants to conserve AND shift load, and derive economic benefit from so doing. Some 270,000 customers subscribed to the program in which they received a fixed time-of-use rate.

The project was ultimately abandoned in the second year as customers withdrew when they discovered that their costs were actually higher than those in the control group. This, despite participants actively shifted load to off-peak periods to take advantage of the lower prices at those times. Unfortunately, the flawed rate structure, introduced to mimic a spot market price, was considerably flattened so as not to introduce financial burden to certain segments, including those with lower incomes. The net result was a rate that did not reflect the marginal cost of electricity production at those times and did not have a significant enough difference between on and off peak to encourage load shifting for financial benefit. In fact, peak prices were 17% higher than mid-day prices but off peak prices were only 12% lower. Customers also paid a $1/month fee to subscribe to the program. Overall, despite the flaws in the program design, energy consumption was in fact reduced by almost 5%, and another 5% of the load was shifted to off-peak times.

For PSE, the cost of smart meter deployment in the field was high as a function of new technology and the relatively small-scale roll-out did not generate any economies of scale operationally. PSE also required extensive modifications to accommodate the new data formats and volume, and integration to billing and customer information systems. The reduction in consumption actually allowed PSE to export power for additional margin since California was experiencing across-the-board energy short-falls, but such benefits eroded in the second year as wholesale prices began to fall.

This program was touted to be the landmark for the effectiveness of smart meters and while it demonstrated that the infrastructure enabled an LDC to make better use of its capacity (and lower the overall costs of such infrastructure from a capital and operating perspective), it highlighted the critical role of a properly designed rate structure to achieve these overall objectives, which are to encourage conservation and to shift load to better fill out the capacity of a distribution system. This message should resound for the Canadian context where time-of-use rates are not widely applied.

Time-of-use rates and the role of dynamic pricing are discussed in greater detail in Section 5.

3. Potential Markets and Providers

In Canada, the potential market for smart meters is significant, as is the associated potential revenues for AMI vendors. A recent study by Tantalus, a Canadian smart meter technology company (See Vendor Profiles Section) estimates the potential at more than 6 Million meters and more than $1 Billion in revenues.

Table 3.1 Canadian Potential

Sector	Units	Revenue
Residential	6,294,162	$ 1,029,095,444
Commercial	218,603	$ 89,180,024
Total	6,512,765	$ 1,118,285,468

The largest market is in the Residential sector, which has also seen the least amount of deployment. Smart metering, and related automation and command and control has penetrated the large commercial and industrial sectors already, and there are a number of successful providers who are active in these markets. Large-scale deployment in the residential sector in Canada is mainly un-known. Clearly, there is a huge un-tapped potential market.

3.1 Vendor Profiles

There are several categories of vendors offering components or complete solutions to AMI/AMR systems. They include meter data management solutions as premise hardware including individual telecommunications modules mounted "under glass," data concentrators to which multiple modules may direct data, and meter asset management and deployment solutions to organize mass deployment of meters. As market demand continues to grow, new companies are emerging making the competitive landscape more cluttered and the solutions more complex.

This section contains a review that highlights the extent to which technology has been developed. While SMI solutions have been deployed more strategically (hard-to-reads, drive-by areas etc), the rapid evolution of AMR to more legitimate SMI class systems coincides with the proliferation of advanced wireless communications technology, the recognition that LDCs across North America are facing the end of the useful lifecycle of traditional metering technology, and the penetration of time based rates to help optimize infrastructure capacity.

Technologies are available for a broad spectrum of applications. Power line carrier technology is provided by a number of vendors and is well suited for long low speed low bandwidth data transport (for rural applications for example) as well as two-way command control functionality. Other fixed network solutions including drive-by and telephone based systems offer low-cost automated reading capabilities but are more geared to automated meter reading. There are also a number of companies with residential mesh wireless meter technology (e.g. ZigBee) that incorporates full two-way communications between the premise devices and central data collection system.

Some of these vendors have developed extended functionality that includes tamper and theft detection, remote disconnect, load control, and SCADA type functionality. To the extent that few LDCs have made sizable purchases of the most advanced smart metering systems with the above-mentioned capabilities, vendor systems are being designed to enable this type of functionality (facilitated by the use of open standards communications protocols, modular boards to allow for “swapping” telecommunications cards, and using radios to communicate with similarly equipped in-house control devices for load control purposes). The distinction is that few vendors have invested in building large inventory of their most advanced systems as demand has not been sufficient to justify. Most are ready to build in response to such anticipated demand.

SMI vendors provide fixed network solutions that are physically connected to communications systems, as well mobile/wireless systems that use public wireless networks. In addition, SMI solutions are classified as one way or two in terms of communication. More basic systems propagate data from the premise device to the central system, while two-way systems can upload information to the device, request data, perform diagnostics, and initiate actions.

With regards to the data management component, there are also several vendors with advanced solutions that integrate meter data acquisition, which includes acquisition, verification/editing, warehousing, and formatting. Several solutions include integrated meter asset management capabilities to track location and status of devices in the field, to ensure that meter data is coming from a particular device and that the device is attached to the correct address/customer account number. This is particularly critical in the domain of smart metering as meters that are taken out of service and then installed at new locations must be accurately tracked at all times to ensure the correct data is coming from the correct devices which are installed at the correct account.

Mass deployment of smart metering introduces an additional layer of logistical complexity as meters, once installed, must be tested and configured to “register” on the network and be recognized by the central system. In addition, the delivery of large quantities of meters (provisioning) to the field by geographic location must be managed and several vendors have provisioning solutions to manage that aspect of the deployment project.

Appendix A of this document provides an overview of major providers active in Canada today. It is not intended as an exhaustive discussion of the marketplace but it is certainly representative of the technologies and their current status. While prices continue to vary as a function of quantity and functional richness, it is anticipated that significant orders (in the 100s of thousands of units) will precipitate price reductions to below $100 per point. Many utility customers have determined that two-way systems provide not only the richest functionality but minimize the risks of stranded assets by ensuring the premise device does not require field service at any point in its lifecycle due to changing tariffs, software upgrades or other diagnostic activities.

The list of vendors provided in Appendix A supports a representative view that the major technologies are at an advanced stage of development and commercialization. Many have integrated much of the potential functionality into production systems while others are now looking to integrate load control and SCADA functionality into their solutions to provide a utility-wide platform for operations optimization and infrastructure management.

3.2 Leading Edge Developments

As mentioned, the leading developments in this sector in essence are focused on packaging more functionality into the device. This requires reduction in size of several elements within the meter/module including printed circuit boards, and telecommunications boards. In the meter industry, the trend is towards the consolidation of the meter to the printed circuit board level and ultimately to the chip level. This trend will “free up” space within the meter and permit the integration of a number of new functional components including remote disconnect/reconnect capability, and load limiting. The wireless telecommunications sector, in particular the manufacturers of handsets, have been actively reducing the size and cost of GSM and GPRS radios and are consistent with the requirements of SMI manufacturers.

Since a large component of smart metering infrastructure is the communications capability, the deployment of SMI provides a potential platform for outbound communication as well, and not only for device management purposes. The ability to communicate price signals to the customer and load control signals is of great interest to system operators and regulators who view the meter as the ubiquitous device to provide this access and communication pathway.

Regulators are also interested in leveraging this infrastructure for other essential LDC services including water and natural gas; several systems are capable of capturing multiple streams of data that enhance the business case for mass deployment of SMI.

With respect to data transport, the monitoring, command, and control of electricity consuming devices in real-time is an important consideration, and several vendors have developed technologies that can provide real-time data transport functionality using the Internet or wireless broadband solutions. Related to data transport is the issue of data security. Data integrity and security are becoming important considerations for LDCs. The transportation of data over public networks introduces an array of new risks, particularly data relating to SCADA parameters, such as:

- Command & Control capability;
- Instant outage reporting and restorative capability – enhances system reliability;
- Continuous power quality monitoring – problem analysis enhances efficiency;
- Remote disconnect capability – eliminates costly off-cycle reads;
- Power theft detection (1-2% revenue loss);
- Real time communication with large number of field device sets;
- Cycling capability (by location, type, load etc) vs. rolling brownouts to manage impact;
- Instantaneous peak shaving;
- Immediate impact report of load shed via smart metering;
- Real time signaling;
- Remote Thermostat (HVAC) control; and,
- Power factor control.

Discussions regarding the upgrading of utility infrastructure have precipitated additional debate over how such regional communications infrastructure might be leveraged beyond the realm of utility operations. For example, it has been proposed that stand-alone private networks be deployed to support utility applications and emergency response applications for medical and police, utility mobile work management, and even broadband services to remote communities. It is understandable that what begins as an exercise about upgrading utility metering infrastructure rapidly escalates to discussions about an entirely new high band-width, secure, wireless communication platform able to layer on multiple applications. It is ironic that the very technological advancements that enable SMI are proving to be an obstacle to its own implementation as stakeholders wrestle with the fundamental concept of what this infrastructure *might* support given the one-time opportunity to upgrade it on a mass scale.

4. Barriers and Challenges

Theoretical papers deduce that improved efficiency, reduced market power and increased reliability are generated by more price responsive loads (eg. time-of-use, real-time pricing). Clearly, there can be a wide variety of barriers, including those related to the technology(s) and those related to the market and infrastructure.

4.1 Market Related

A significant portion of North America's electricity infrastructure is arguably at the end of its technology lifecycle. While much of the asset base is serviceable, the existing infrastructure is unable to deliver the functionality that is being identified as critical capabilities in an era where the coincident demand is outstripping existing generating capacity in some jurisdictions and exceeding the capacity of the delivery infrastructure in others.

Utility metering at the residential level and to a large degree the commercial and industrial sectors is based on antiquated technology. The explosion of intelligent devices and telecommunications technologies is revolutionizing how data flows in all pathways and how that data can be utilized. The utility sector is no different. Many electricity distribution companies are leveraging their rights-of ways and fiber optic networks to participate in the explosive demand for bandwidth across urban centers. Interestingly, they have been less successful in leveraging these same technologies in their core businesses of managing the distribution of electricity, ironically for the very same reasons of rapid technology evolution.
It is because of the rapid evolution of these technologies that the risks of stranded assets increases as product lifecycles become increasingly compressed.

The simple analogy that most consumers have experienced is the dilemma of when to purchase a personal computer i.e.: now when one needs it or later when the next generation processor chip is introduced. The new reality is that technology obsolescence is part of the equation. But technologies with standards based designs, modular/bolt-on platforms, as well as upgradeable firmware and software, will be serviceable in the longer term.

4.2 Regulatory and Institutional

The benefits of smart metering accrue regardless of the degree of regulation. Nevertheless, it is essential that retail prices either reflect a strongly competitive wholesale market or reflect shadow prices that would have prevailed if a complete and competitive wholesale market was in place. However, significant regulatory barriers to the full realization of the benefits of smart metering include the freezing of retail rates (e.g., periodically in Ontario and Manitoba), having uniform rate schedules across all classes (one size fits all), and insulating customers from price volatility.

In some jurisdictions, there is tremendous regulatory uncertainty about who will eventually own the meters, related equipment, and the data generated from smart meters. There is concern that investment today in the technology might become a stranded asset tomorrow.

An important consideration is that there is not a great deal of experience from which the sector can draw regarding market-based hourly prices for residential and small commercial customers. System operators have focused traditionally on the supply side and have ignored the demand side. They need to recognize the reliability of benefits of using large numbers of small loads that can quickly respond.

4.3 Technology Barriers

The technology barriers are likely not as significant as the market barriers. The technology is evolving such that integrated intelligence with command and control capability (representing the leading edge of the technology) is becoming available in the marketplace, and there are a number of providers. Convergence of technology and its effective operation in an integrated platform will define that new market. Technology innovation with respect to stand-alone systems is somewhat limited and changes are likely to be linear and incremental. Platforms that integrate multiple technologies, communications systems, and command and control are not as well developed or defined. Indeed, there has not been a major residential based demonstration of this kind of application. Given the complexities of the various technologies and the challenges that typically accompany complex integration, any integration of this nature will bring certain technical challenges. Regardless, it is evident that there is already some capability in the market to address these technology challenges.

4.4 LDC Perspective

The market barriers are more profound and for the moment, are limiting the widespread adoption if the technology(s). Policy, regulatory, pricing and other market oriented issues represent major hurdles for widespread deployment. As well, as with any new technology, adoption may involve undertaking a certain amount of risk. The aversion to risk is particularly strong as it relates to smart meters as the most likely purchasers or purveyors of smart meters are electric utilities, either provincial or LDCs. Both entities have an over-riding imperative to provide safe, reliable power. For the moment, it is apparent that in Ontario, the LDCs are taking a “wait-and-see” approach to smart meters.

As part of the supporting research for this Paper, a number of LDC Managers and staff in Ontario were interviewed for their perspectives on smart metering. Their views supported the notion that non-technology barriers were preventing greater smart meter deployment. In particular, uncertainty around government direction (including who will be paying for the smart meters), lack of price signals, and uncertainty around which systems represent the best investment were paramount.

LDCs are also aware of what has occurred in other jurisdictions. A few months after opening the restructured California market, it boasted numerous competitive meter service providers (MSPs) and meter data management agents (MDMAs). Unfortunately, procedural barriers such as price caps, approved utility meter replacement credits, and other barriers eventually forced most of these providers out of business. Recognizing that at least some of these elements have not been addressed in Ontario, the LDCs are wary of making large-scale investments, in spite of the apparent needs and opportunities.

4.5 Technology Provider Perspective

From a provider perspective, the risk of investment in stand-alone systems versus development of interoperable systems clearly favours the stand-alone systems. For now, the marketplace is not sending signals as to the preferred direction: consolidation of multiple applications on a single platform versus acquisition of multiple stand-alone systems, particularly as function of cost. With the unique role that LDCs play in dictating the market need, this issue may defer to utility-based or regulatory decision-making.

As indicated earlier, large-scale deployment at the residential level has not occurred. Deployment in the large commercial and industrial sectors is occurring as a result of market drivers. Ontario is in a leadership position in terms of policy and planned implementation, however that market has adopted a “wait and see” position. Ontario also has the most pressing capacity and infrastructure issues related in part to rapidly growing population, limited large-scale generating options and timelines, aging heritage assets and a commitment to take coal plants out of service for environmental reasons. Ontario is also the only Canadian jurisdiction contemplating the enactment of legislation to mandate the deployment of smart metering and as such, other jurisdictions (and all vendors) are watching with great interest to see how the plan will be implemented. Smart meters are being installed in other jurisdictions, but largely as a result of pilot type projects or in response to specific needs. It is likely that the Ontario experience will set the tone for developments in the rest of Canada.

5. Technology Impacts

Section 5 examines the expected reductions in electricity use that might occur as a result of deployment of (residential) smart meters. It also considers pricing and rate issues.

5.1 Engendering Reductions in Electrical Power

This section is principally concerned about the electricity demand reductions coming from the usage of smart meters. The focus is on the potential reductions from the small electricity consumer, that is, the residential and small commercial customer. This discussion can be conveniently discussed under the following topics: (i) instantaneous direct feedback, (ii) time-of-use rates, (iii) dynamic pricing, and (iv) reliability programs and automated load control. Aside from the utility, the key participant that makes these demand reductions possible is the customer.

5.1.1 Instantaneous Direct Feedback

A real time meter integrated with an in-house display provides immediate direct feedback to the customer. The resulting conservation coming from this more frequent feedback of information varies, depending on whether accompanying rate incentives and/or conservation information and incentives are offered. With just real time feedback and no other accompanying policy, Mountain (2006) estimates from a recent Ontario pilot that an average 6.5% reduction occurs; for some customer groups (e.g., those with electric water heating) the decrease is as high as 16.7%. Generally, the reduction associated with direct electronic feedback is between 5% and 12.3% (Van Houwelingen and Van Raaij (1989) and Darby (2001)).

The tendency is that with more conservation information and conservation goal setting the reduction pushes toward 10%. Generally, the more detailed is the breakdown among the end-uses, the higher are the savings. For example, 12.9% reduction was observed by Dobson and Griffin (1993) when sub-metered loads were reported back to the customer. Furthermore, as much as a 20% reduction may be possible in cases where we move from group to individual metering. While there is growing evidence on an experimental basis, the evidence tends to come from relatively small pilots, where only single factors are being tested. Little evidence is available for either a utility wide program or on a large scale regarding integrative programs (e.g. real time electronic feedback with time-of-use price incentives and in-home displays).

5.1.2 Time-of-Use Rates

Obviously, a smart meter offers the possibility of time-of-use rates (different rates for different times of the day, where the rate structure is fixed). Generally, the larger the price differential and the shorter the time interval of the peak period, the larger the impact. In the Ontario residential time-of-use experiment conducted between 1982 and 1988[2] rate structures with 16-hour peak periods and a peak to off-peak price ratio of 2.6:1 showed a reduction of 5.6% in January and those rate structures with a peak to off-peak price ratio of 3.9:1 showed a reduction of 6.9% in January. For rate structures with a narrower peak period, such as a 9-hour peak period, with a 3.9:1 peak to off-peak price ratio, there can be as much as a 12.5% reduction in the peak during January. Similarly for July, rate structures with a five-hour peak period and a 3.9:1 peak to off-peak price differential, the reduction is 12.8% in the peak period. It is clear from this early study that even without two-way communication, smart meters through time-of-use rates can enable significant reductions in consumption at critical times of the day.

More recently a relatively small price differential of 1.3:1 ($0.0625 per kWh in peak and $0.0470 per kWh in off-peak) used by Puget Sound Energy reduced peak demand by 4%.

Time of day impacts for the commercial sector (non-industrial) tend to be less than that of the residential for some experimental results for small commercial customers.[3] Nevertheless, while the per establishment impact is less, for some LDCs where the commercial load can be between 40% and 50% of the total load, the overall impact (on a kW.h basis) can be of the same order of magnitude of that of the residential sector.

5.1.3 Dynamic Pricing

Smart meters that incorporate real time pricing offer a new level of incentive to the small commercial or residential household. This potentially allows minute-by-minute change in electricity price. It also allows for the possibility of critical peak pricing, pricing that focuses on the hours surrounding the peak. A recent study shows significant response where participants were provided with an interactive communication device to pre-schedule major energy-using activity during the normal time-of-use period and during hours where there are abnormally high prices in response to wholesale price signals sent over communication lines.[4] In fact, there was a reduction of 26% on weekdays of the hottest summer months during which temporarily high prices were occasionally sent to the customer. Reductions by as much as 50% during the hours with the highest wholesale prices were also recorded. Where the customer is able to see the wholesale price, the reduction can be several times greater than estimates of other studies where customers did not have such a communication technology.

[2] Mountain, 1993
[3] Ham, Mountain and Chan, 1997
[4] Braithwaite, 2000

Further research is warranted regarding the interaction between the smart meter that allows such dynamic reporting and in-home display and the various interactive pricing policies. A distinct obstacle has been a reluctance of regulators and LDCs to permit small customers to see true market price signals. In effect, LDCs and regulators are currently insulating customers form market price signals. Ultimately, to ensure more efficient markets, the end users must receive the market price signals. New pricing programs will emerge which reflect the "two-part nature of electricity, the commodity and the insurance service"[5] Customers may be able to purchase insurance through fixed price contracts to protect themselves from the volatility of electricity prices or they can self-insure, by managing their own electricity in response to dynamic prices.

A benefit of allowing the end-user to see the wholesale price through smart meters is the mitigation of price spikes in wholesale markets. In fact, it can be shown that with only a small percentage of customers responding to the wholesale prices leads to significant reductions in possible price spikes at the wholesale market level. Studies have shown that even if only 20% of the retail load responds and even if their load shows a very low price elasticity (e.g., -0.1), the "effect on price spikes, price volatility, market-power abuses, mix of new generation constructed, and overall electricity costs will be substantial."[6]

Another significant benefit from dynamic pricing, time-of-use pricing, and real-time pricing is conservation. While most dynamic, time-of-use, or real-time pricing programs focus on reduction of peak demand or shifting of demand from the peak to off-peak period, an auxiliary benefit of these pricing programs is overall conservation. There are three reasons for this conservation:

1. Not all of the reduction in peak hours is shifted. Some of the reduction (e.g., reduce lighting) is not recovered;
2. Dynamic pricing programs cause customers to have a higher awareness of their energy; and,
3. These programs usually increase the quantity of usage information or feedback. More information tends to lower consumption. The result of 24 studies that reported this conservation in the residential sector, show an average of 4.0% reduction.[7]

5.1.4 Reliability Programs and Automated Load Control

Reliability programs using load controls can focus on meeting or avoiding system or local transmission peak emergencies. This could include interruptible and curtailable programs for commercial customers and direct utility control of residential air conditioners and water heaters. The focus is on demand reductions, not energy, for a limited number of hours (e.g., 100 hours per year).

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[5] Hirst and Kirby, 2001
[6] IBID
[7] King and Delurey, 2001

Usually customer incentives are offered in exchange for allowing for the control of their water heater and/or air conditioner. Initial results indicate significant reductions. A recent study[8] examined the impact of water heater controls accompanied by time-of-use pricing in a residential experiment in Norway. When a universal signal for automatic disconnection of water heater is sent, the average load reduction is 0.39 to 0.57 kWh/hour per household for morning hours, and between 0.20 and 0.65 kWh/hour per household in the afternoon. Usually at any one time the disconnection affects 20 to 30% of the water heaters.

Nevertheless, there is a flyback of up to 0.36 kWh/hour in the morning and 0.22 kWh/hour in the evening. But, generally the flyback is much less than the original reduction. A recent example reported for Public Service Electric and Gas of New Jersey estimates a payback of about 40% of the amount of air conditioning load reduced during the peak.[9] Of course, some cycling of load reductions across households is appropriate for bypassing the problem of a post load control peak.

Recently, Hydro One launched a similar study exploring the impact of load controls on water heaters and/or air conditioners. While the results from this study are not yet available, it is noteworthy that there is only one-way communication. It does not allow for customer overrides via the smart metering technology. As well, with only one-way communication load controls, there is no allowance for the utility to receive feedback on the extent of load shedding that is actually occurring. This kind of program typically results in 5% to 10% reductions in load per appliance as the customer does not actively participate in the control of the equipment. Rather, the utility manages the load remotely. In the short term, these kinds of efforts can be expected to be used by the LDCs in Ontario to meet specific load reduction goals.

5.2 Expected Reductions in Electricity Use

The evidence supports the notion that a 4% to 10% reduction in both peak demand and energy is realistic from smart meter installations. There is the potential for a fairly wide variance, depending (particularly) on the sector – residential versus industrial and commercial with the residential generally yielding more modest results. The effectiveness will in part be driven by the existence (or not) of time of use rates, with higher results expected when these rate structures are in place, especially for the industrial sector which may find more opportunities to shift load. Even without time of use rates, metering capability that includes user friendly displays of real time usage can be expected to generate savings (particularly in the residential sector) as consumers voluntarily respond to the information.

[8] Ericson, Saele and Finden, 2004
[9] Goldberg, 200

6. Potential Benefits to Canada

Benefits can be anticipated from both the expected electricity and emissions reductions, and through the dynamic effects of a potentially significant investment in new infrastructure and capability. This applies equally to the technology providers and the myriad of supporting service providers. The opportunities to leverage other capabilities, including greater participation in utility sponsored energy efficiency programs also arises. Quantifying all the various benefits is outside the scope of this paper but they are likely to be significant. Given Canada's well-developed communications infrastructure and capability, there is also an opportunity to amplify an already existing strength.

6.1 Emissions Impacts

Section 5 provides an estimate of the magnitude of the potential savings on a per unit basis. In the residential sector, 4% to 10% electricity savings have been demonstrated. Other sectors can realize even higher savings. Depending on the generation mix, these would directly translate into GHG and other toxic gas emissions reductions (for provinces where there is a predominance of coal generation, the GHG and other toxic gas emissions reductions would be greater than for provinces where there is a predominance of "clean" generation).

There are two important considerations for applying this potential reduction to the market to estimate the impact. This value represents the potential from a technical perspective. The total impact will be dictated by the economic and achievable potential, which forms the basis for the market penetration. From these perspectives, the total impact will be somewhat less.

Without the benefit of knowledge regarding the nature of the pricing structures and the regulatory direction, it is difficult to estimate what the market penetration will be. Estimating the impact is further complicated by the issue of persistence. Where savings rely on enabling technology, with inherent behavioural or non-technology based reductions, there can be issues of slippage, whereby consumers revert to their old patterns of use. This represents a risk for the long-term determination of savings. That said, it does appear that the potential savings can be significant.

6.2 Potential Strategic Investments

Currently, there are over 20 major providers of smart metering (and related) technology in North America. With relatively few large-scale market deployments (particularly residential) and many providers, one could argue that there is excess capacity and that the technology is currently ahead of market demand. Given the number of RFPs issued in the last year, it appears that the gap is shrinking. Incremental investments in smart metering technology may serve to drive the price down but do not necessarily represent innovation in the technology itself.

The market has not yet articulated what might be characterized as a generic product (i.e the baseline functionality). Without that experience, it may be premature for SDTC to postulate the appropriate strategic investments. However, it does appear that integration represents the most likely next level of innovation and providers that can bring unique integration platforms are likely to have a strategic advantage as the market evolves.

6.3 SDTC Experience to Date and Context

Since one of the considerations relates to the consolidation of multiple applications on a single platform versus acquisition of multiple stand-alone systems, the question for SDTC is what is the intrinsic innovation in an integration exercise? For SDTC, consideration must also be given to the likelihood of the integration occurring as a result of a normally functioning market evolution, i.e. as a result of market demand.

Over 7 rounds of funding, and approximately 1000 applications, SDTC has received approximately 40 applications that generally fall into categories associated with smart metering. Upon closer examination, only 10 fit the more precise definition of smart metering application. Of these, there have been less than 5 that represent innovation related to integration of a suite of smart metering technologies.

It appears that smart metering manufacturers are focusing their development on optimizing their existing smart metering technology, rather than exploring the ways and means to expand functionality by considering the integration of other technologies to broaden the application. Broadened applications would facilitate other activities including demand management and distribution automation. Given this opportunity, there does appear to be a gap between what the market potential might be, and what applicants collectively are bringing forward to SDTC for consideration

7. Summary

Challenges exist at many levels in the implementation for smart meter infrastructure. It is clear that there is not a single technical solution that can be implemented across a distribution territory and therefore certainly not across the country. The task of defining the necessary functional requirements of such a system has been equally challenging, as the technology can deliver extensive functionality all of which comes with incremental cost, and operational risk. Advanced meter infrastructure has many elements; the meter, an embedded data telecommunications device, a data concentrator/collector, a communication pathway (be it private or public) and a data repository/management system. With innovation in device integration, this infrastructure can provide not only billing data, but also robust functionality for SCADA, demand response, customer communications, and a variety of utility operational efficiencies for tamper/theft detection, outage detection, disconnects, notification for Critical Peak Pricing periods and other direct consumer communication.

The smart metering technology is evolving rapidly and the ability to embed richer functionality is essentially transforming the meter, a device to facilitate billing, to a fundamental element of utility infrastructure for much broader operational efficiencies. The stakes are high for LDCs in selecting smart meter technology for this very reason. The proposed Ontario smart metering project represents a one-chance opportunity to deploy a new technology platform. This commitment will either constrain or enable future functionality which will largely define the opportunity for a wholesale upgrade of metering and a significant portion of the market. Smart metering is a utility billing tool that allows for the accurate measurement and billing of electricity consumption and while it enables certain conservation and load shifting opportunities, it in and of itself is not a conservation technology. As an enabling technology the implication is that it is only as effective a tool as supporting policy and regulations that will leverage its capabilities to deliver economic and system benefits to stakeholders.

From SDTC's perspective, there is currently a relatively low penetration of smart metering technology. As such, there is a gap between the current technology and market demand (technology is ahead). However, the regulatory mood across North America reflects the urgency to relieve grid congestion and move to the real-time domain. In addition, aging infrastructure is facing obsolescence and together these elements indicate a tipping point in the sector suggesting that the sector is at the front end of a technology revolution. While the electricity sector is currently ahead of the water and natural gas sectors, scarcity of supply and the need for more effective management of these resources will drive technology innovation into these areas as well.

In this context, it is anticipated that with market adoption and education, it will not be long before a new cycle of innovation, driven more by users than technology evolution itself begins, and it is therefore incumbent on SDTC to closely follow these innovation cycles and consider appropriate strategic supporting investments. In particular, projects that can demonstrate the most advanced technology integration, and bring the relevant market actors who have the authority to put in place the appropriate price regimes and regulatory engagement, offer an interesting proposition for SDTC.

APPENDIX A: TECHNOLOGY PROVIDERS

Appendix A provides a list and short discussion of the major technology providers in Canada.

EMeter Inc.

EMeter, established in 1999 offers data management software solution to manage data delivered by a variety of AMI/AMR systems. Called the Power Information Platform, the eMeter solution provides asset management functionality to bridge the gaps between existing IT infrastructure and the more complex data and telecommunications capabilities of AMI/AMR systems and the data relationships between assets, premises, customer accounts, users, applications and services to manage AMI/AMR programs from field deployment to on-going operation. The web-based platform provides access to meter data from any location without geographic constraint. eMeter integrates data from diverse communications protocols from wireless and powerline carrier, from telephone-based to RF mesh systems. EMeter positions itself as the implementation partner to allow the utility to lead and manage its own AMI/AMR deployments.

The company offers a variety of supporting consultative services to develop the cost-benefit analysis to planning and logistics for implementation and will undertake complete design-build responsibility, working with a variety of strategic partners to deliver fully integrated functionality, using standards-based communications, ANSI standard meters, and compatibility with a variety of leading enterprise application software including Siebel and Oracle.

Lodestar Corporation

Lodestar provides a comprehensive suite of applications for energy companies to act as an integrated, comprehensive single system of record and to manage virtually all aspects of their operations. Lodestars Energy Information Platform (EIP) goes well beyond meter data and asset management. Lodestar Enterprise Data Repository architecture underpins the EIP and CCS application modules, designed to import, manage and validate complex data sets to optimize operations.

The are a variety of supporting applications including those aimed at setting prices, contract development, portfolio management, transaction management forecasting and meter data management.

Tantalus

Tantalus, established in 1989 is a Canadian company that offers two-way utility meter data communications technology using wireless WAN and LAN devices.

Its TUNet system integrates functionality for meter reading, load management and distribution automation over a common communication infrastructure.

Tantalus is one of a few companies that incorporated the WAN communications into its solution rather than leveraging existing public carrier GSM or GPRS telecommunications infrastructure. The TUNet deploys a 220 Mhz wide area network consisting of a network Controller installed at a radio tower, communicating with multiple transceivers installed throughout the service territory. The Network Controller is accessed using standard TCP/IP protocol. At the device-level, the wireless meter reading module is integrated under glass with the utility meter communicates to adjacent meters and ultimately to the WAN transceivers using a 900Mhz spread spectrum RF. Modules can be polled directly or programmed to report on a fixed schedule.

The device level functionality includes the detection of voltage variations, power outage reporting in real time. Meter data includes interval and time-of-use measurement. Devices are remotely programmable and suitable for operation with single-phase electronic and electro-mechanical meters and certified by Measurement Canada for Elster, GE and Westinghouse meters.

Smartsynch

Headquartered in Jackson Mississipi, Smartsynch offers wireless and wired smart metering communications over public carrier networks for industrial and commercial utility customers. Smartsynch has offices in Calgary and recently announced an Ontario office.

The company’s technology is like many now, standards based, using XML protocol, J2EE, and ANSI for end device tables and telephone communication. The company’s products include its SSI meter module which monitors all the tables in the electronic meter and provides the communication gateway to Transaction Management System (TMS) via the public WAN infrastructure. Smartsynch claims near-real-time transmission of data.

The TMS system is designed with full provisioning capabilities for the deployment and management of smart meters in the field. The Java based application platform is designed to exchange data with MS SQL Server as well as Unix based Oracle enterprise platforms, and based on client-free browser-based application access.

Using packet-switched communication, smart meters transmit data to base receivers which in turn deliver it to the “back-haul” high speed WAN network to the TMS. Schedules can be created to synchronize data transmission with billing cycles and on-board memory allows the module to record and report on a variety of events. Functionality includes the ability to transmit register data, reset demand registers, request frequent interval reads, advise power outages, establish alarms and thresholds, detect tampering and retrieve diagnostic flags. TMS provides a variety of data management functionality including importing CSV files, exporting HHF and MV-90 data formats, and interval data trending reports.

Trilliant Networks

Trilliant Networks was launched from the previous company NERTEC Design Inc., based in Quebec. Trilliant is relatively unique in its technology evolution in that it focused on interval data communications from the start as its core capability. It began from telephone-based communications and has developed among the most advanced wireless communications platforms leveraging the ZigBee-based 802.15.4 communication standards for its short-hop RF mesh solutions for residential, and full GPRS communications capabilities for commercial smart meter modules and data concentrators. It provides all-utility data transmission solutions for its customers and is actively engaged in a variety of pilot projects with Ontario based LDCs and its US customer base.

Trilliant offers full two-way communications smart metering solutions, integrating data backhaul over a variety of pathways including CDMA, GSM, and iDEN for its mesh gateway product line. It has received Measurement Canada Approval for integrating its mesh modules into the Landis&Gyr Focus and Itron' Centron meters.

Trilliant has selected the2.4 GHz unlicensed radio band for its mesh products which claims a range of up to 3km fully powered. It provides up 45 days (depending on the interval) of internal data storage and monitors fully the resident ANSI tables. Their MeshReader module can be programmed for scheduled communication or polled in real-time, on-demand. The module can report outages, transmit load profile data, tampering and a variety of diagnostics. All diagnostics, configuration and programming for critical peak pricing, tiered tariffs etc., can be remotely managed.

The Meshreader is an "always-on" IEEE 802.15.4 protocol device capable of communicating at 250 KBPS and does not require a battery for normal operation. The MeshGate, Trilliant's cellular network gateway communicates with its proprietary ServiewCom data management software which is accessible by utility clients using a web-based browser or if desired can be installed at the client facility. The Meshgate is either embedded in Trilliant's commercial/industrial smart meter product or serves a data collector/concentrator in residential mesh applications.

Trilliant offers an out-sourced meter data collection service through its WebRead that is essentially its ServiewCom application served over the web as an ASP service.

Itron Inc.

Itron is among the largest providers of products and services to the utility sector. Established in 1977, it is the largest provider of metering technology and data management solutions shipping several million modules annually. It's portfolio of products and services includes a number of acquisitions including Silicon Energy (energy management application), Regional Economic Research Inc. (analysis and forecasting software),eMobile Data Corp. (web-based workforce management software) and LineSoft Corp.(T&D optimization software).

Itron also has a breadth of data collection and data management solutions from it's well-known "Mobile Collection" (RF drive-by) multi-utility AMR solution which automatically polls meters on a vehicle-driven route and uploads consumption and tamper data to a billing system

Itron also offers a fixed network system based on it's ERT end-point device which transmits wireless through a series of repeaters to a fixed network backhaul pathway and has a range of approximately 3-500 feet. The modules communicate (1-way) directly to a Cell Control Unit (CCU). As such, the system has more pole-mounted collectors than in a mesh network scenario. The ERT's transmit over 900Mhz frequency to the CCU and from there over 1.4 Ghz to Network Control Nodes. The 2.0 version of the solution offers interval data capabilities to a resolution of 5 minute intervals and can use public GPRS, PSTN, or Ethernet as to transport data back to the central data repository. Meter modules record and transmit consumption, demand, time-of-use. This system is a low bandwidth communications capabilities limited to meter data collection. Itron also offers conventional hand-help meter data recording devices used for typical route-walking reading activities.

CellNet

CellNet offers a fixed network solution for mesh residential AMR utilizing unlicensed 900Mhz for end-point communication of asset, consumption demand, time-of-use and load profile data. The Company is one of the earlier AMR companies and has in excess of 20 million end-points in operation, for electricity water and gas. End-point modules, suitable for retrofit to both electronic and electromechanical meters are suitable for Landis&Gyr, GE, and Elster 120V and 240v singlwe phase residential meters.

Cellnet's WAN network modules, called the InfiNet gathers data from endpoints (a polling system) and transfers wireless data to the backhaul network which includes am IP addressable gateway device called the Take-out-Point. Network components are mounted at height on poles, light standards etc. As a result of the significant number and size of field-deployed components, CellNet's solution is better suited for high density applications. CellNet also offers a “head-end” software solution to manage the planning, deployment, management, and maintenance of its fixed network system.

The company also offers its Enterprise software solution with tools to support the lifecycle of the AMR project, including planning, deployment, configuration, operations, and on-going maintenance. Enterprise software deployed manages about 10 million end-points for various customers.

Elster

Elster’s Metering was acquired from ABB electricity metering and part of Ruhgras Industries group, which was acquired by CVC Capital Partners of the UK in 2005. The metering division includes multi-utility and energy metering technology as well as load control and smart metering products.
Elster’s smart metering solution is based on the EnergyAxis, system a fully two-way communication network that includes a 900MHz “mesh” network to its proprietary REX single phase residential meter. The REX meter provides functionality to transmit kWh consumption, kW demand, time-of-use metering, critical tier pricing (CTP), and load profile interval data. AS with many mesh systems, the REX meters register automatically upon installation. The REX meter communicates to the data collector and periodically uploads data to the Elster’s Metering Automation Server over public telephone carrier networks.

Cannon Technologies Inc.

Established in 1987 and headquartered in Minneapolis, and privately held. Cannon began in business as a software company developing products for utility distribution automation and load management. As its application platforms evolved, it integrated forward to communications devices and began to invest in powerline communications technology. Its product portfolio includes solutions for demand response (web-based remote curtailment, control and monitoring), distribution automation (substation monitoring and capacitor control), and energy information, under which its meter data collection, analysis and presentation reside. Cannon is also one of the companies that specifically identify the integration of meter data collection and demand response capability.
Best-known for its powerline carrier (PLC) platform, Cannon has many utility clients in low-density) rural areas where long distances make wireless communication less reliable/cost-effective . Related to smart metering, Cannon offers an array of hardware and software to provide a complete system to the utility.

Beginning at the premise level, Cannon’s two-way fixed network is based on its powerline carrier technology and a communications module also has storage for numerous data sets including TOU, load profile, and outage information. The bi-directional system is capable of on-demand reads in near real-time (the company states less than 6 seconds from issue of command). Meter modules in a given territory communicate with the “substation coupling” installed at the substation servicing it.

To address another area of utility operations, Cannon offers a 200A service disconnect meter that can also operate in a load-limiting mode. The device utilizes the same communications infrastructure. Cannon’s PLC solution is compatible with Sensus and Itron single phase meters.

For commercial applications, Cannon offers an externally mounted (separate from the meter) communication unit to provide similar functionality to poly-phase commercial meters.

At the central control end of the solution, Cannon offers several industry-standard server based solutions to manage data and control scenarios for its field-installed network systems. For meter data, Cannon offers its Yukon platform which can manage data from a variety of communications pathways from its own PLC to satellite. The company states that the Yukon application can format meter data compatible for most commercial billing systems and also can integrate to other Yukon-based applications. Available in either a web-based subscription or a site-installed application, Yukon’s *Meter Data Collection Server* provides functionality to support rate analysis by enabling accurate aggregation of diverse meter bases and providing a real-time web-based display.

Cannon offers to the utility sector one of the more complete product portfolios targeting not only meter data collection but broader distribution system automation and controls. Cannon has directed its product development in alignment with the LDCs interest in a single platform upon which to operate and manage multiple applications.

Hunt Technologies Inc.

Based in Minnesota, Hunt offers a product line focused on meter data collection based on its fixed network powerline carrier technology with a population of over 4 million end-points in service. It’s communication technology is an *under-the-glass* module effective for low-bandwidth communication of meter data over long distances as is the economically attractive characteristic application of PLC technology. Hunt also offers *Airpoint*™, its RF solution based on a licensing agreement with Itron’s ERT unlicensed mobile data collection system.

The PLC product portfolio has two solutions, the TS1 which is its low cost 1-way communication for meter data collection and the TS2, a fully two-way communication solution that includes recognized functionality of time-of-use scheduling, outage detection, load control, and remote disconnect.

For data collection and management, Hunt offers a data collection software application, the *Command Center™* which boasts compatibility to a variety of utility data interfaces for the ability to integrate to other utility applications to leverage the system for efficiencies in other aspects of the utility operations.

As is the industry trend, Hunt also offers its data collection and management solutions as an ASP service, through a secure web interface to provide access tot he Command Center functionality without on site software, and embedded disaster recovery, server management and traditional hosting services.

Distribution Control Systems Inc. (DCSI)

Located in St. Louis Missouri, DCSI is a subsidiary of ESCO technologies Inc. and manufacturers its PLC based Two-Way Automatic Communication System (TWACS). DCSI has been in operation since 1978. DCSI promotes the advantages of a PLC-solution based on leveraging existence and de facto 100% coverage of the end-users distribution infrastructure.

The TWACS meter module, the Integrated Meter Module (IMT), available in several configurations performs both scheduled and on-demand reads and supports demand reads and remote resets. Compatible with a number of major meter manufacturers (Itron, L&G,Its optional functionality enables critical peak pricing, multi-utility reads (gas and water utilizing its 3-port IMT) and the recording of interval data. Meters can be grouped for synchronized reads and the central system can broadcast messages to grouped of devices. To support accurate settlement, the IMT can collect and transmit interval (hourly) data to support real-time pricing, load profiling and research activities. Other functionality of interest to the utility includes outage detection, tamper detection, and service disconnects. DCSI provides modules for both residential (single phase) and commercial (polyphase) meters. Also available from DCSI is hard-disconnect collar that attaches to the standard meter base. It houses a 200A 4-jaw form, addressable disconnect along with a communication module.

TWACS meter modules communicate to substation-installed interfaces (Substation Communication Equipment, SCE) which in turn are on line with the central system application server (the TWACSA Net Server, TNS). The SCE backhaul communicates over a variety of “voice-grade” communications paths (phone, radio, coax etc.).

In the area of load control, DCSI offers its Load Control Transponder (LCT), a stand-alone residential load control module that operates on the common TWACS connecting up to two of household loads. Communicating through the existing SCE, the LCT accepts commands from the Central Control Equipment master software which allow large numbers of loads to be grouped and controlled with commands executed at the device level in less than one minute. DCSI also offers prepayment meter solutions. DCSI does not have readily available information regarding its meter data collection software.

Echelon Inc.

Echelon is a publicly traded network communications company, probably the best-known provider of PLC-based communications with its proprietary LonWorks communication protocol which it has licensed to hundreds of device manufacturers, from thermostats to elevators, chillers and other distributed asset classes.

In 2005, Echelon provided the PLC embedded technology for the world's largest mass deployment of smart meters in Italy with some 25 million meters field installed as part of the 70 million unit project. Although the design of the meter was geared for the European market (lower amperage per home, and higher number of devices per transformer) the company is actively promoting its smart metering system the Network Energy Services, the NES platform, a two communications pathway linking a customer end-point device to a transformer mounted data concentrator, and to a central software system. Focused primarily at residential applications (suitable for light commercial), the NES platform supports an extensive array of features including pre-payment, multi-utility AMR, outage detection, tamper detection, distribution system monitoring, load control and power quality measurement.

APPENDIX B: GLOSSARY OF TERMS

Aggregation Forming a large group of entities that together can bid for the total or displaced capacity into commodity energy markets.

AMI Automated Meter Infrastructure. Includes end-premise devices, “head end” software applications, related hardware, and telecommunications pathways

AMR Automated Meter Reading. Hardware and software related to remote meter reading.

Asset Management Systems that track location, identity and status of distributed assets in the field including meters.

BPL Broadband over Powerline. Telecommunications technology to transmit high band-width data over powerlines.

Demand The rate at which energy is delivered to or by a system, part of a system, or a piece of equipment. It is expressed usually in kilowatts electricity, m^3 of natural gas, or Btu of thermal energy.

Demand Response The process of organizing and controlling disparate and distributed energy loads in response to system or price signals with the purpose of reducing demand during periods of high price or high consumption. In several jurisdictions, avoided demand is bid into markets just as additional capacity.

Demand-side When looking at the entire system as a whole, the portion that determines the amount of demand; furnaces, motors, lights, etc.

Deregulation Process of removing regulatory authority over regulated companies. In a deregulated environment rates and services will be determined by the market place in much the same manner as other consumer goods.

Distribution The act or process of delivering energy from convenient points on the transmission system to distribution networks and through to consumers. The network that distributes, transports, or delivers energy to customers.

Distributed Generation Small independent generating facility that supplies energy to through the distribution infrastructure (compared to larger plants that connect to the transmission grid.

Energy Management Act of monitoring and utilizing energy consumption data in order to maximize usage efficiencies and provide information for energy procurement strategies.

End-Point Device The premise installed meter or component at the point of use.
Firmware Operating software that controls hardware device

Generation Act or process of producing electric energy from other forms of energy. Also refers to the amount of electric energy so produced.

Grid Generic term referring to the network of transmission and distribution infrastructure serving a specified geographic territory.

GSM/GPRS Telecommunications platforms used by wireless phone carriers

HVAC Heating, Ventilation, Air Conditioning systems.

ICI Term to represent Industrial, Commercial and Institutional sectors

LDC Local Distribution Company or utility

Load The amount of energy delivered or required at any specified point or points to meet demand. Load originates primarily at the energy-consuming equipment/systems at end-ser facilities.

Load Serving Entity Any party, including any Transmission Owners taking Transmission Service on behalf of wholesale and retail energy customers, who has undertaken an obligation to provide or obtain energy for end-use customers by statute, franchise, regulatory requirement or contract for load located within or attached to the Transmission System.

Load Profile A curve on a chart showing energy supplied, plotted against time of occurrence, and illustrating the varying magnitude of the load during the period covered.

Load Control Devices or systems used to dispatch on/off commands to aggregate and control electrical load**.**

MegaWatt (MW, MWe) Megawatt (MW) is a unit of power, is equal to one million watts, and refers to the heat output of a reactor. MWe refers to electrical output.

MeshNetwork A collection of peer devices that transmit data to an end-point using low-powered wireless transmitters/radio signals

OEM Original Equipment Manufacturer.

Off-Grid Also referred to as an energy island, facilities that do not rely on utility infrastructure for their energy requirements.

PLC Power Line Carrier. A technology that transmits data over electrical wires.

SCADA Supervisory Control and Data Acquisition. Utility systems to provide status of critical points in the transmission and distribution infrastructure.

SMI Smart Meter Infrastructure. Synonymous with AMI.

LDCs LDCs are distinguished as being a class of business "affected with a deep public interest" and therefore subject to regulation. Public LDCs are further distinguished in that in most jurisdictions it is considered desirable for them to operate as controlled monopolies. As such, they are obligated to charge fair, non-discriminatory rates and to render safe, reliable service to the public on demand. In return, they are generally free from substantial direct competition and are permitted, to earn a fair return on their investment.

WAN Wide Area Network. The telecommunications infrastructure used to transport data over long distances.

Workforce Management Systems that enable automatic dispatch of service in response to system generated exceptions or trouble-shooting.

Zigbee An emerging wireless communications protocol allowing for short distance unlicensed communication based on a recognized IEEE standard.

APPENDIX C: REFERENCES

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