Ontario

Smart Meter Initiative

Cost Considerations Working Group
Notes of Meeting #2 – Sep 15/04
9:00 am – 3:30 pm

Ontario Energy Board
24th Floor - Meeting Room #1
2300 Yonge Street

Attendees:	Julie Girvan	Consumers Council of Canada
	Martin Malinowski	Rodan Meter Services
	Sagar Kancharla	Enbridge Gas Distribution
	Andy Poray	Hydro One Networks
	Randy Aiken	London Property Management Association
	Anne Rampado	Burlington Hydro
	Dave Wilkinson	Cambridge Hydro
	George Armstrong	Veridian Corp
	Art Skidmore	Halton Hills Hydro
Regrets:	Paul Ferguson	Newmarket Hydro

1.0 Notes of Meeting from Sep 7/04 were reviewed and amended as follows:

1.1 Notes referencing electromechanical meters will be revised to also reference electronic meters in order to recognize that EM meters are not the only technology being used.

1.2 Note 3.1.8 – replace the word “will” in the second sentence with the word “may” to reflect the possibility for an ongoing role of NSLS.

1.3 Note 4.2.2 – remove the word “quite” in third sentence and replace the word “low” with “lower”.

1.4 Note 4.3.1 – the note was expanded to reflect the option of tiering flat rate recovery within customer classes according to consumption

1.5 Note 6.1 was revised to recognize the distinction between reverification and compliance sampling

1.6 An additional note numbered 6.3 was added to identify redeployment of stranded meter hardware as a potential cost mitigation strategy

2.0 Matters arising from previous meetings:

2.1 The subject of meeting notes detail was discussed and a sample of the template used in the DSC study process was examined. The concensus was that, although the template has some desirable features, it is time consuming to use. Given the short timeframe in which the group must operate, it was decided that the current meeting note format should be maintained. It is possible that the DSC template method might be useful in constructing the final report.

3.0 Stranded asset minimization strategies – cont'd from last meeting

3.1 CIS stranding can be minimized by keeping the pricing structure simple. Complex pricing structures may overwhelm customer systems and require significant effort and cost to upgrade and/or replace.

3.2 The Minister's directive notes that the Board can authorize installation of smart meters for customers with loads in excess of 50 kW as soon as it deems it advisable and without further reporting to the Minister. An early start on converting these customers would help to minimize stranded metering assets within that customer class.

3.3 The electronic business transactions hub system (EBT) may be affected by a complex regulated price plan (RPP). Minimizing complexity of rates would assist in keeping the EBT system viable.

4.0 Unbundling meter charges

4.1 Capital costs

4.1.1 The capital cost of smart meters is expected to be greater than that of existing electromechanical and/or electronic accumulating and demand meters. Similarly, there will be additional costs to convert or replace existing interval metering to achieve smart meter functionality.

4.1.2 LDC ability to finance capital costs will need to be addressed.

4.1.3 Depreciation period for the metering pool is currently 25 years. Electronic meters may have a more limited useful life because they are more vulnerable to technological obsolescence. Therefore, the depreciation period for smart meters should be shortened to avoid stranding assets in the future. A regulatory change will be needed to authorize this.

4.2 Installation costs

4.2.1 Installation cost will be influenced by the deployment plan adopted. If smart meters are rolled out on a cycle basis then installation costs can be minimized. Individual customer requests for a smart meter will have to be discouraged to avoid customer specific costs for installation.

4.2.2 Damage to some customer meter bases and internal equipment can be expected during the conversion program. Meter bases that have been in service many years might be damaged or mechanically degraded to the point that even careful extraction may cause failure. Alternatively, human error in removing the meter may cause arcing that can damage the base and/or affect sensitive customer electronic equipment connected to the system

4.2.3 If semi skilled contract workers are employed to complete residential changeovers it is likely that a flat rate per meter change will be sought to control costs and this may not encourage safe and careful work techniques. The liability costs of this situation may need to be addressed.

4.2.4 If multi utility reads are to be incorporated in the installation, more skills will be needed by the installer, coordination between participating utilities will be needed and the possibility that inspection of wiring by ESA may be necessary. These factors will all add costs to the installation.

4.2.5 If an in home display module is required to communicate load and price information to the customer, installation may be more complicated and costly.

4.2.6 Inventory storage and handling costs may be significant if mass deployment within a utility is adopted. However, this is probably the most effective strategy from an overall cost perspective.

4.2.7 Deployment of the AMR system may require mounting structures in neighbourhoods with underground distribution systems unless they can be mounted on street lighting poles. If dedicated structures are needed, municipal approval will be necessary and, depending on how obtrusive the structures are, opposition from residents may be expected.

4.2.8 The cost per point of the communication system will vary with the type of system selected and the geographic features of the deployment area.

4.2.9 Professional installation of communication infrastructure will likely be needed which may strain available resources.

4.3 Bulk Metered Facilities

4.3.1 Centrally metered apartments, condominiums, trailer parks etc. will face special challenges if they are to be included in the smart meter initiative. For those buildings that have centralized HVAC systems and/or laundry facilities, central load control can be exercized by the building management. For those that have such amenities in each unit, central control is not practical. Because of the number of customers that may fall into the latter category, not including them in the smart metering deployment might overlook a significant load shifting opportunity.

4.3.2 Retrofitting existing submetering systems to smart meter functionality will involve costs that might have to be addressed if the building owner's cooperation is sought.

4.3.3 Submetering systems present other issues that will need addressing

4.3.3.1 If all such customers are adopted by the LDC, customer care costs will increase but so will revenues as each pays the fixed customer charge. If the number of customers involved are significant, the LDC might have to adjust its rates to compensate for under or over recovery.

4.3.3.2 Leases and condominium agreements will need to be revised to reflect direct billing by the LDC of electricity costs.

4.3.3.3 Approval of the Rental Housing Tribunal may be required to permit direct billing of apartment renters that presently pay for utilities in their monthly rent

4.4 Maintenance

4.4.1 Electronic meters may be less robust and more vulnerable to technological obsolescence than mechanical ones presently used. This would imply greater repair/replacement frequency and if failures result in throwaways, as currently happens with many electronic devices, overall costs may be substantially higher.

4.4.2 Initial reverification period for the most common type of electromechanical meter (single phase, magnetic disk type) is 12 years whereas electronic meters have only 6 years. Even if a manufacturer is able to justify a longer period, the maximum is currently set at 10 years. This will result in more frequent compliance sampling of meters and significantly increase maintenance costs.

4.4.3 If a battery is required in the meter to maintain memory during power interruptions, routine on site maintenance may be required that is not a feature of meter maintenance today.

4.4.4 Communication system maintenance and troubleshooting costs are new costs not incurred in the present system.

4.4.5 Maintenance of software systems associated with data collection will be a new cost for the residential class of customers that is not incurred in the present system.

4.5 Reading

4.5.1 Current manual reading costs will be eliminated. For urban utilities this cost is estimated to about $0.50 per read. Many utilities read on a bimonthly basis, some on a quarterly basis. The annual cost of manual reads per customer then is in the two to three dollar range.

4.5.2 Read accuracy is reportedly higher with smart metering systems than with manual reads. This should translate into lower customer care costs as inaccurate read driven complaints should decline. There may also be some benefit from a cash flow point of view if the customer is billed on actual data rather than estimates.

4.5.3 The cost of final reads will be lower because a site visit will not be necessary as it is now. Similarly, remote check reads may also be more economical as long as meter malfunction requiring a site visit is not the cause.

4.5.4 Inside meter installations cause special access problems for meter reading that often causes an LDC to resort to estimated bills. Access costs and inaccurate estimates will be largely eliminated by smart meters.

4.6 Settlement and Billing

4.6.1 Commodity true up costs will be a feature of any pricing system that does not use actual market prices. The administration costs of the regulated price plan will therefore be a feature of smart metering that was not present in the original market pricing model. The costs will depend upon the complexity of the RPP.

4.6.2 More frequent billing to enhance cash flow is often cited as a potential benefit of smart metering. However, improved cash flow must be balanced against the cost of preparing and sending bills more frequently. For example, if the cost to prepare and send a bill and to process the resulting payment is $1.00 then at least that amount must be gained in avoided financing costs by billing more frequently. It is arguable that the average customer bill financing cost per month is as high as $1.00 even including the reduced bad debt risk exposure. When the effect of equal payment plans that most utilities provide is factored in, the cost of more frequent billing may exceed the benefits.

4.6.3 Customer service costs are expected to be higher at least during the transition phase as customers become educated about smart metering and resulting changes to the way electricity is priced.

4.6.4 Smart metering objectives may conflict with other objectives such as capping rate impacts. If customers are insulated from price signals then load displacement may not be achieved. If, for example, retailers offer fixed price contracts to mitigate risk, customers will have not economic incentive to shift load or to conserve at peak times.

4.6.5 The DSC mandates that LDCs offer equal billing plans to mitigate the volatility of electricity costs. These plans may conceal the true time of use impacts of electricity pricing and defeat the DR objective of load shifting.

4.7 Operations

4.7.1 Remote disconnects will be less costly and in some cases less confrontational than manual disconnects. This will be a benefit to LDCs. It is important to note, though, that a significant part of the disconnect process is notification often entailing delivery of a notice and this feature will probably not be any less costly with smart metering. This feature assumes a bidirectional communication system will be available to LDCs.

4.7.2 Remote reconnect capability may not be as useful because of the liability associated with reenergizing a service without ascertaining that someone is home to turn off any appliances that might have been operating at the time the service was interrupted. Presently, utilities require that the customer have someone at the site to cover this risk. However, telephone confirmation of attendance might satisfy this requirement in which case remote reconnects would reduce costs.

4.7.3 Automatic outage notification to a LDC control room is suggested as a benefit of smart metering. This functionality is possible but may require features such as battery backup in the meter that would impose additional maintenance costs. The system would also have to distinguish between missed communication as the reason for lack of a signal and a real outage to avoid unnecessarily dispatching a repair crew.

The present system usually relies on individual customers to call the LDC when the power is out and they can usually be relied upon to do so promptly. Even if a customer is not home when an outage occurs, most are fed contemporaneously with other customers from a transformer and it is rare, at least in an urban setting, for an outage to go undetected. More importantly, the time expended on identifying that an outage has occurred is a very small component of overall outage duration. Response and repair is the most significant part of the process and this will not be affected by smart metering. Therefore, the benefit of smart meter detection of an outage is nominal at best.

Confirmation of voltage restoration is a benefit of smart metering because it should allow LDCs to check that all customers affected by an outage have been restored before the repair crew leaves the area. This would avoid the cost of a second crew visit to restore a customer who was overlooked.

4.7.4 Distribution system optimization may be facilitated by smart metering because detailed customer demand and consumption data will be available that can be aggregated to various system levels. Improved load factor, for example, would support more efficient distribution system usage and translate into lower costs per customer for system components and for line losses.

4.7.5 Operationally, accurate customer coincident demand data aggregated to transformer level would provide an early warning of overloading that could prevent an outage and avoid equipment damage.

4.7.6 Theft of power may be detected more easily if it involves meter tampering. However, theft accomplished by tapping conductors before they reach the meter would not be detected by smart metering. The benefit may not be significant if most power is stolen by this latter method. However, aggregated load data by transformer would facilitate comparison with transformer capacity and help an LDC determine if meter bypass was a likely cause of overloading leading to a failure.

4.8 Data Storage and Management

4.8.1 The costs of data storage and management will be higher because of much larger volumes of data being generated by smart meters. This assumes that data retention for seven years will continue to apply to smart metering data.

4.8.2 Present LDC customer information systems may not be capable of storing and manipulating this volume of data. Vendors of these systems need to be consulted to determine the impact of smart metering and to determine the extent of modification or replacement that will be necessary.

4.8.3 Presently customer billing information is accessible on line for most enquiries. The volume of data necessary to answer customer questions about a smart meter bill may not be accessible on line.

4.8.4 Regulatory requirements for resolving customer complaints may have to be examined in the context of what is practical from a data storage and access point of view.

4.8.5 LDCs may not have the expertise to store and manage the volume of data that will be generated by smart metering. It may be necessary to outsource much of this function. Costs associated with data storage and management cannot be quantified until the smart metering system specifications have been developed.

4.9 Meter Record Management

4.9.1 Because meters will not be visited regularly in the smart metering as in the manual reading system, data input errors may be harder to catch. For example, meter registration data can be cross checked against customer data when a manual read is done and errors discovered. Meter damage and evidence of tampering can be detected with regular visits. Remote reading sacrifices this regular inspection and LDCs will have to alternate ways of detecting errors.

5.0 The next meeting will be September 20, 2004.