Guelph Hydro Electric Systems Inc.

MEMO

TO: **J. A. MacKenzie** **DATE: November 25, 2004**

FROM: **Engineering and Operations/Metering**

SUBJECT: Smart Meter Implementation Plan Comments

COMMENTS FROM ENGINEEERING & OPERATIONS/METERING on RP 2004- 0196

We wish to encourage rational thought before significant resources are again invested in another initiative, without conclusive evidence that the investment will result in the desired outcome.

Other Options:

There are other options that may be more suitable than smart metering in residential interval metering format as an investment to encourage modified energy consumption patterns and an energy efficiency and energy conservation culture:

1. **Power Factor Penalties**: Before the redesign of the electricity market, there was a greater emphasis on encouraging "energy effectiveness" via a greater cost (penalty) on customers with poor power factor. The impact of poor power factor penalties was significantly reduced with the redesign of the market, effectively a disincentive on improving efficiency in energy use. Perhaps implementing billing on kVA instead of kW demands would again encourage an energy efficiency culture, specifically in the customer classes with demand metering;
2. **Residential Time of Use:** Implementing residential time of use (along with other strategies and initiatives) may be more cost-effective at achieving provincial energy efficiency and energy conservation goals than implementing smart meters. The cost of implementing time of use will be significantly less expensive, less onerous and will have a shorter implementation timeline;
3. **Demand Time Stamp:** Perhaps a single monthly or daily demand with a recorded time stamp might be a more cost effective way of recording customer demand peaks for the customer classes <200kW. LDC systems for meter reading data gathering, CIS and Billing Systems would be much less significantly impacted than the requirements for upgrading and managing these systems with 720 monthly data (and potentially rate) intervals. Costs for acquiring, validating, calculating, storing and presenting this data for this class would be greatly reduced. Full interval metering for the > 200kW class is more readily achievable with less overall impact and cost;
4. **Prepayment Meters:** The draft document recommends that prepayment meters be permitted under "grandfathering" as part of the smart metering initiative, but that any new prepayment meters must be outfitted with the ability to gather hourly interval data. This requirement is despite the fact that field studies have proven that the prepayment

meters installed in several jurisdictions reduce energy consumption by an average of over 15%, including one municipality in Ontario with a reduction of well over 20% relative to the non-prepayment meter. **Appendix D – Monitoring and Measuring 5% Demand reduction** indicates a target of a 5% demand reduction across the province. The insistence of interval metering technology in the face of above evidence of success is difficult to understand, and leads one to question the underlying justification for residential interval metering;

5. **Total Capital Cost**: Has a cost-benefit study been performed on the estimated (we believe underestimated) capital cost of the proposed residential interval smart metering program? A smart meter on its own will not accomplish anything, it is simply an expensive tool, most likely to simply shift energy consumption patterns, rather than actually curb energy usage. Should we consider options such as investing $1 billion upgrading energy inefficient industrial processes, lighting, or perhaps further developing energy from waste, district heating or co-generation facilities.

Costs Higher Than Estimated:

Our experience with meters, metering interrogation and translation systems and communication systems since the 1970s leads us to suggest that the costs of a residential interval metering system implementation will be significantly than then estimated in the draft report.

1. **Section 4.4.1 – 95% Read Transmission Success Rate / Appendix C-2 Smart Metering Costs #3 & #6**: The draft document proposes a 95% transmission read success rate, and estimates OM&A costs of $0.20 / meter / month and data editing and validation costs of $0.01 / meter / month. We believe the true operating costs for a running this system will be higher.
   a. **OM&A**: Our existing industrial/commercial interval metering population of 131 interval meters (109 interval metered accounts) on MV90 currently consumes approximately 700 hours annually for data editing & validation, as well as attending to and resolving local field issues with the electronic meters, communication medium and devices, or for gathering replacement data in the event of a communications failure. We attempt to gather, validate, edit if necessary and process for settlement on a daily basis, and for this larger class of customers (currently > 300 kW at our utility), we take great care with the customer data. We have seen many examples of the issues with all of the components and devices that comprise the data gathering and translation system. Since embarking on an expanded electronic meter population for the new market, we have experienced a much higher failure rate of the electronic meters when compared to their electromechanical predecessors. We have suffered through several re-programming of electronic meters that were not capable of performing as advertised, to the extent where one style of meter was twice reprogrammed, and is now is the process of being removed from service. We have witnessed numerous unexplained “spikes” in customer data within MV90, while clean data still resides within the meter. We attribute these anomalies to communications issues, and following suitable investigation, re-retrieve the proper data from the meter’s memory instead of simply estimating replacement data. The costs of this are estimated at about $35 / meter / month. While we would expect some automation is feasible for the residential customer class, we nevertheless believe the estimate of $0.21/ meter / month to be low.

b. **Communications**: Communication statistics for our current telephone line based (15% dedicated phone line, 85% call processor on customer owned phone line) system indicate an approximate 10% - 15% daily communication error rate. We note that the daily successful interrogation rate is better than the 10%-15% communication error rate, as our calling retry strategy picks up the majority of the failed calls, but within a more liberal timeframe (we do not expect to have data processed for posting to a web site by 8:00 am the following morning). We understand that the IMO experiences about a 2% daily error rate on more sophisticated wholesale metering installations. The draft plan suggests a minimum 95% success rate over a 3 day period. On a 45,000 meter population, a 1% - 5% daily error rate range would result in 450 to 2,250 daily exception reports. At this point without further details on technology options, and event clearing parameters, it is difficult to determine the resources required to respond to this requirement of the proposed smart meter implementation plan.

c. **Daily Data Posting by 8:00 am:** The requirements for data gathering, preliminary presentment for customer access, missed read logging, editing and presentment, etc speaks to the need for additional resources to address the proposed requirements. We again suggest that the estimated costs may not reflect the eventual reality, and wish to again pose the question, "***What evidence exists that setting up systems to operate as described above will have the desired effect with respect to modifying customer behaviours in a positive way***?" Many residential customers have time commitments for work, children, school, etc that may override the notion that having yesterdays hourly interval data available by 8:00 am the following morning will be a driver for change. For a few weeks immediately following the Blackout of 2003, Ontarians did practice more of a conservation ethic, but this ethic evaporated a month following the blackout restoration. Are there better ways of spending this capital to have a guaranteed effect?

2. **Appendix C-3: Stranded Costs #10** An estimated Interval Meters value at about $1,500 per interval customer is identified. Most of these installations at our LDC were installed at a time before some direct cost recovery was permitted by the code. The cost of the communication medium, typically a call processor and telephone line, was borne by the LDC. A more realistic estimate is approximately $2,000 per single Metering Point (MP) customer installation.
3. **Appendix C-3: Stranded Costs #10**: Many larger customers will be supplied by more than one MP, for a variety of technical reasons. In this scenario the customer's bill will be calculated from a totalized data stream from the multiple customer MPs. For these customers the estimated cost per interval customer will be about $2,000 per MP, or $6,000 each for our larger customers. At our LDC, for 109 interval metered customers, we have installed and need to daily manage the data flow from 131 interval meters.
4. **Pg. 36 – 3.3**: In a practical sense, most electronic meters cannot be retrofitted with communication devices, as this would be just as expensive as purchasing a new meter. Stranding electronic meter assets will need to be considered. Retrofits meters may not be compatible with the smart metering technology nor direction a distributor takes.
5. **Pg.38 – 3.4.1 & 3.4.2**: Our current CIS is designed for billing customers and retaining relevant consumption and payment information. The system was never designed for nor intended to report on a complicated system of customers with various rate classes. With the multiple rate configurations and introduction of various class exceptions (MUSH, MUSH+, etc), it has become much more complicated and cumbersome to setup, record and report on various configurations. Similarly, our corporate Work Order and

Accounting systems (for expenditure tracking) were designed and set up in a time when reporting requirements were more straightforward – they were not set up for gathering costs based on frequently changing customer classes retained in CIS and Customer Billing systems. Introducing any additional complexities will further put a strain on limited resources. Again, the ratepayer will ultimately pay for this cost. Adding smart meter costs to only those who have the smart meters installed would introduce additional difficulties in billing procedures and tracking creating sub-classes of customers by class.

Measurement Canada Requirements:

Measurement Canada (MC) is a federal agency, with a mandate to service all of Canada in the area of metrology. Our experience with MC leads us to suggest that it may be naïve to believe that MC will be prepared to relax or modify existing well established metrology requirements simply to facilitate the new Ontario electricity market.

1. Throughout the Smart Meter Implementation Plan – Appendices reference is made to various reports and studies performed in different jurisdictions in different countries. Some of the study findings are not transferable to the Canadian experience, as some of those jurisdictions do not have an equivalent to MC;
2. **Appendix C-1: Smart Metering Benefits #7:** MC has a requirement for an annual physical meter reading for devices deemed to be a form of Automated Meter Reading (AMR). Refer to Section 9 of the Electricity & Gas Inspection Act – this requirement is identified via specific meter approvals by MC. Our understanding is that MC has an obligation to verify the synchronicity of meter register reads to transmitted reads, including true AMR devices (ie meter radio register), as well as electronic interval meters currently used with existing meter interrogation and data translation systems (MV90). LDCs would use the meter's mass memory (interval) information to generate billing quantities, while the meter would continue to record kWh register reads. These register reads must still be verified by an annual physical read, according to MC requirements. ***The draft smart meter implementation plan does not take this requirement into account. Some cost savings identified and promoted in the draft document suggest that physical reads are no longer required with an AMR system, as manual reads will be displaced. Our understanding is that meter reading costs will not go down as suggested, and another process will need to set up to accommodate the MC requirement, in addition to the daily processing requirement.***
3. **Appendix C-3: Stranded Costs, Appendix D-1 2.5 Element Meters:** MC has recently discontinued allowance of 2.5 element meters for new metering installations. A wide scale smart metering program requiring upgrading of the meters to either 2 or 3 element as appropriate would introduce costs that are not reflected in the draft document.
    a. **Page 81-82**: replacing a 2.5 element meter with a 2-element meter and delta connection at the test block is not endorsed as a viable solution by MC, and should not be an option;
    b. **Secondary Metered 2.5 El:** ***estimated costs for reconfiguring this to 3 element secondary metered range from about $500 to $1,000 per installation direct costs plus the costs associated with a plant shutdown, if necessary***. Note that our LDC has no plans to change existing 2.5 el mechanical meters until they fail, and when they do fail, no plans to upgrade to a 3 el metering installation – this cost is not reflected in the draft document;
    c. **Primary Metered 2.5 El:** ***estimated costs for reconfiguring this to 3 element primary metered range from about $2,000 to $10,000 per installation, plus the costs***

of a plant shutdown. Note that our LDC has no plans to change existing 2.5 el mechanical meters until they fail, and when they do fail, no plans to upgrade to a 3 el metering installation – this cost is not reflected in the draft document.

4. **Appendix D: System Requirements – Security of Meter Data:** ***Under MC regulations changes to internal meter readings or reprogramming of any meter function that affects billing, including raw data in a meter, is not permitted.***

<u>Comments Regarding Proposed Implementation:</u>

Below you will find comments related to the proposed plan implementation:

1. **Pg.15 – 2.2.3:** The plan suggests progress reports by the distributor on a quarterly basis. We recommend reporting every six months, as new market implementation already has significant reporting requirements. Reducing the reporting requirement would allow more effort to be placed on actual implementation.
2. **Pg.29 – 2.6.2:** ***Physical meter installation could be accomplished within 4-6 weeks of a customer request if we have meters in stock and available for that service type, and subject to some of the timing constraints of the new market***. Transitioning accounts from non-interval to interval in our existing CIS is to some degree a function of timing constraints of the new market. For example, we cannot final bill an existing customer until we have proper pricing (about 18 days into the following billing period). Not have the account finalized places a constraint on when we can set up the new interval metered account. As a result account transitions are more complicated and require more manual intervention than prior to the new market.
3. **Pg.29 – 2.7**: Coordinating visits to customer homes is ***unreasonable*** since a large percentage of customers are not home during the day, and some customers are hard to contact. This requirement would slow down installation of meters in geographic areas. Also, most meters are located outside the residence, so there is no need for the customer to be present. Performing customer education as we install these meters in the field is not practical, as it is too involved and again would greatly slow down meter changes. Performing a 6-month follow-up is also ***impractical*** unless it is in a mailing format.
4. **Pg.32 – 3.1**: ***If a high percentage of customers choose to go with fixed retailer contracts there is a very high likelihood that there will be no load shedding at peak times from these customers resulting in a minimal and less than desired result on the provincial load***.
5. **Pg.34– 3.1.2**: If retailers are allowed to install load control services it should be independent from the meter so as not to disrupt the meter data acquisition process, especially if the LDC is responsible for the meter data acquisition.
6. **Appendix D-7 Pg.106**: Well established processes for estimating consumption have been in use at LDCs for many years. For consistency purposes we agree that a standardized estimation is suitable, ***however we strongly disagree with the suggestion that LDCs should be responsible for the costs of a zero estimate if comparable periods for estimating are not found. There are many legitimate ways to estimate for a missing read, and ultimately a MC dispute mechanism is available to the customer should the customer believe that the estimated values are unreasonable. We believe the estimating processes established and currently used are fair and reasonable to all.***

7. **Appendix A Pg.7 item #7 1st bullet**: Based on information from Woodstock the display is a key mechanism in up to 20% reduction in usage. This technology of immediate customer information on consumption translated into dollars and cents is easier for the consumer to understand. We recommend the Board focus on establishing meter interfaces for the customer similar to the technology used by Woodstock.

Comments by: Matt Weninger / Hans Paris