DISTRIBUTION SYSTEM CODE TASK FORCE

CHAPTER 5

SUMMARIES OF RECOMMENDATIONS: METERING

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5.1 DEFINITION OF THE WORD "METER"

[LAST DISCUSSED: AUGUST 12, 1999]

Issue Statement

The Distribution System Code (DSC) will contain definitions that are pertinent to the application of the DSC. In researching definitions for terms that are used in the DSC, it became apparent that certain terms have different definitions in various Acts and documents from the OEB. The issue is:

What definition should be used for the term "meter" in the Distribution System Code?

Options

The following definitions are currently in use for the term "meter" in the documents in parentheses:

1. "Meter" means an electric or gas meter and includes any apparatus used for the purpose of making measurements of, or obtaining the basis of a charge for, electricity or gas supplied to a purchaser (Electricity and Gas Inspection Act).

2. "Meter" means a device that measures and registers the integral of active or reactive energy in a billing period, reported as average interval demand, and may include a data recorder but shall be deemed to exclude the instrument transformers (Market Rules for the Ontario Electricity Market).

3. "Meter" means an instrument for measuring power flow normally referred to as the meter, any equipment sealed therein and any external sealed recorder attached thereto; the meter does not include instrument transformers, the meter-communication system or any other equipment that is not sealed within the meter, except a sealed recorder attached to the meter (Final Report to the Ontario Market Design Committee - Appendix A5).

Background Information

In the Final Report to the Ontario Market Design Committee, the subpanel on Retail Metering discussed the boundaries for the competitive market in meter services. The subpanel recommended that the boundary between the distribution system and the competitive meter service market should be the test block. Current transformers (CTs), potential transformers (PTs), secondary circuitry and test blocks should remain the property and responsibility of the distributor. It is important that the DSC coincides with this recommendation as the market begins to develop and a Retail Metering Code is established.

The definition used in Option 1 by Measurement Canada (MC), covers all aspects of equipment used for metering, including the CTs and the PTs. The instrument transformers are part of the record of a metering installation required by MC and all of the components involved in a metering installation are part of the concern by MC to ensure accuracy of the consumed energy. Hence the definition used by MC is very broad.

The definitions in Option 2 used in the Market Rules for the Ontario Electricity Market and in Option 3 used in the Final Report to the Ontario Market Design Committee, specifically exclude instrument transformers. Instrument transformers can be expensive and it could discourage competition in meter services to require instrument transformers to be replaced or purchased by the customer if they are seeking competitive meter service providers. Also, distributors do not want to be faced with the pressure of purchasing instrument transformers back from competitive meter service providers. The discussions at the sub-panel kept the sealed meter separate from the instrument transformers, secondary circuitry and any metering communication systems. They recognized that some self-contained meters currently are available that do not require the use of instrument transformers and that this product likely will continue to develop.

Implementation Issues

The use of a definition for the term meter in the DSC could conflict with the definition in the Electricity and Gas Inspection Act (EGIA). This should be easily resolved by discussion with Measurement Canada as the DSC and the EGIA have two differing purposes.

Summary of Discussion

The definition used in Option 3 is the most common understanding of what a "meter" is for distributors. If a competitive market develops for metering services, the market most likely will involve the sealed meter unit only. The new technologies being developed in metering are mostly for the sealed meter unit, including plug-in metering devices with self-contained CTs and PTs, as well as sealed units containing internal devices to replace the external sealed recorder. It is important to include the external sealed recorder attached to the meter as part of the "meter." This will prevent a competitive MSP from providing the customer with a metering device only to replace a meter/recorder installation and not providing the recorder outputs that are important for electronic monitoring and totalizing of multiple feeders.

The definition used in Option 1 by MC is very broad and can lead to CTs and PTs being included as part of the "meter" at a metering installation. Neither distributors nor customers will want to see this interpretation of "meter" as the market develops.

The definition used in Option 2 may still be too broad and could leave room for debate as the market develops.

Recommendation

The DSC should use the definition from the Final Report to the Ontario Market Design Committee. The DSC, therefore, will be consistent with the discussions from the MDC report and the likely discussions from the Retail Metering Code Task Force once it is formed. The definition is stated in Option 3 above.

Voter Summary

<Vote not taken>

Dissenting Opinions

<Not applicable>

5.2 MANDATORY INSTALLATION OF INTERVAL METERS

[FINALIZED: MARCH 9, 2000]

Issue Statement

Interval meters that are read within a settlement period (MIST meters) impose benefits and costs on market participants. As a result of the benefits, it may be useful to impose a mandatory interval meter requirement on certain customers. However, installation and maintenance of these meters imposes a system cost. The question of whether interval metering should be mandatory is only relevant to retail customers, since wholesale customers are required to follow IMO metering standards through the Market Rules. The issue is:

> Should MIST interval metering be mandatory for certain customers?

Options

1. Interval metering should be mandatory for all customers over prescribed levels of energy consumption or demand.
2. Interval metering should be mandatory for customers whose demand impacts the net system load shape (NSLS) by a designated percentage during a prescribed period of time.
3. Interval metering should always be at the customers' choice.
4. One of the above, with the addition or exception of all new customers.

Background Information

Before considering any proposed options, it is important to be aware of the following points:

- The Retail Settlement Code (RSC) states that load measured by MOST meters (interval meters settled outside the settlement time period) will not be subtracted from the system load profile.
- The IMO set the benchmark for embedded generation at 1 MW.
- According to the Standard Supply Service Code, a distributor is required to make hourly prices available to large volume customers (defined as consumers who demand greater than 50 kW) either through interval metering or through load profiling.
- The metering subgroup reviewed the practices of a few utilities, and it did not find an industry standard for when interval metering is mandatory.

- MIST (Meter Inside Settlement Time) meters are interval meters with communication, so that they can be read weekly.

- MOST (Meter Outside Settlement Time) meters are interval meters that do not have communication capability, so reads are done on a regular schedule (e.g., monthly, bi-monthly, or according to some other schedule).

Implementation Issues

The cost of the meter and the difficulty involved with installing communication lines for existing customers impair deployment of MIST meters on a wide scale. To comply with the RSC requirements for MIST metering, dedicated, rather than shared phone lines, are expected to be necessary. However, it should be noted that there are alternative communication technologies to telephone lines.

It may not be fair to force a particular class of customer to pay hourly spot market prices as opposed to prices set according to a profile. Also, it may be difficult to determine how customers who had interval meters installed as part of load studies should be billed.

While MIST meters are the preferred metering technology, need exists to balance between achieving an accurate NSLS, meeting the demands of customer choice and deploying interval metering over a wide area.

Some utilities have installed interval metering on all customers 500 kW and higher. In some cases these meters were installed at the cost of the utility. Allowing the distributor discretion in establishing a threshold below 1 MW would assist these utilities in achieving equal treatment of customers within their service territory.

Summary of Discussion

The question of mandatory interval meters touches on many issues. There appears to be sound reasons to make interval metering mandatory; the most prominent is reduced potential for cross-subsidization between large customers with anomalous consumption patterns and small customers profiled using the net system load shape (NSLS). Load tracked with interval meters (MIST meters) will be subtracted from the system load profile to yield the NSLS. This will result in Standard Supply Service (SSS) customers paying rates that more closely reflect their consumption patterns.

Interval meter customers, on the other hand, will pay “actual” costs, as their rates will be directly related to the spot market hourly price with an interval meter. With MIST metered customers removed from the NSLS, SSS customers will not be affected, either positively or negatively, by those interval-metered customers.

On the other hand, mandatory interval meters have downsides that should be carefully considered. Mandating interval metering reduces or removes elements of customer choice, a notable aspect of the *Electricity Act, 1998* and the *OEB Act, 1998*.

The working group is comfortable recommending a threshold of 1 MW, as the group felt that customers demanding more than this amount could have a significant impact on the majority of NSLSs utilized by distributors in Ontario. The subgroup noted that the Market Design Committee report recommended a threshold of 50 kW; however the group was concerned about the overall cost to install interval meters for all services over 50 kW.

The subgroup explored the possibility that a 1 MW threshold could put a burden on large distributors (i.e., Toronto, OHSC). Members also discussed the option of setting a percentage-type threshold, but opted for the simpler MW threshold. Larger utilities that were represented (Toronto, Ottawa, Mississauga) were not concerned about the 1 MW threshold, as they felt they already met or surpassed this threshold under existing practices. Many utilities already have installed interval meters for customers at or above the 1MW level. It is expected that the number of 1 MW customers within any single distribution service area would not be excessive. As noted above, some utilities have installed interval metering on customers 500 kW and higher.

Many small utilities presently retain the services of other utilities for billing and interval metering functions. This option will remain for those utilities that presently do not have the computer systems or software necessary to handle MIST meters. As the wholesale market unfolds, additional qualified parties will emerge to serve utilities.

The subgroup discussed whether or not a distributor has a responsibility for promoting or ensuring an accurate NSLS. This topic was a recurring issue. It generally was felt that while the distributor has no incentive to safeguard the SSS customers against unrealistic costs derived from the NSLS, some safeguards should be built into the DSC.

The subgroup noted that customer Load Factor could have a significant impact on the NSLS, but it could be more difficult or complicated to set a threshold using the combination of Load Factor and Demand. The group felt that the distributor would be in a position to know the effect of customer Load Factor on their NSLS; therefore, the distributor could be allowed some level of flexibility to develop additional policies and criteria and apply a lower threshold to customer classes on a non-discriminatory basis. Some task force members expressed concern over allowing distributors the discretion to implement other mandatory interval metering thresholds within their service territories. Members expressed concern about variations in distributor customer treatment. For example, a distributor may have its own threshold or a single customer with multiple delivery points may receive different treatment from community to community.

The task force also discussed the possibility of phasing in lower thresholds over a period of several years. In the end, the subgroup suggested that by giving customers the option to choose interval metering (addressed in another SOR), deployment of interval metering will occur gradually according to market forces. In addition, retailers may include metering packages among their offerings to consumers.

The subgroup discussed the feasibility of requiring MIST metering on new installations 500 kW and higher as an alternative to lowering the threshold over a period of time. The group noted that the incremental cost to install MIST metering at the time of construction is significantly lower than in a retrofit situation. It is beneficial to encourage deployment of interval metering and for customers who demand greater than 500 kW and subsequently can influence the NSLS.

Recommendation

Option 1is recommended.

1. MIST metering should be mandatory for customers when their average of the previous 12 monthly peak loads is 1 MW and above.

2. New installations that are forecast by the customer to be 500 kW or higher shall be MIST metered.

Voter Summary

Majority.

Dissenting Opinions

Some members expressed the opinion that the distributor has an obligation to ensure that the NSLS is representative of the customer to which it is applied. To that end, some members expressed the view that the DSC should allow distributors some discretion to establish a lower threshold above which interval metering would be mandatory. Such a threshold would be applied in a non-discriminatory fashion. In utilizing its discretion to establish a different threshold, distributors should be allowed to consider other characteristics such as Load Factor to ensure that the NSLS is not distorted by a particular class of customers.

5.3 INTERVAL METERING – CUSTOMER OPTIONS

[FINALIZED: MARCH 9, 2000]

Issue Statement

Like many of the other issues, the question of determining when interval metering should be available to a customer generated discussion on many interconnected issues. The group considered when and where Interval Metering needs to be available, why it is necessary in certain cases, whether it would be appropriate to set availability thresholds and circumstances in which a customer should be able to switch back to Standard Supply Service (SSS) Load Profile type billing. The issue is:

Should Interval Metering be available to all customers?[1]

Options

1. Interval metering should be available to all customers.

2. Interval metering should only be available to customers that are not Standard Supply Service (SSS) customers.

3. Interval metering should only be available to customers that meet certain criteria.

Background Information

The following information provides background information on the subject of customers' options with regard to interval metering:

- The MDC report recommends a competitive metering threshold of 50 kW or 12,500 kWh; customers who demand more than 50 kW per day or 12,500 kW per hour should have interval meters.

- The Standard Supply Service Code Section 2.5.3 specifies fixed pricing for small volume and residential consumers under 50 kW. Customers who demand greater than 50 kW are to be billed according to the weighted average spot market price, weighted according to metered measurement or determined by load profile.

- The percentage of customers above 50 kW varies among utilities. One utility found that less than 1.5% of its total customer population falls into this category.

[1] This SOR should be considered in conjunction with SORs on Mandatory Interval Metering and Customer Responsibility for Interval Metering.

- Cost issues and questionable savings may deter some consumers from taking advantage of Real-Time Pricing (RTP). Cost issues may also deter customers on Interval Metering from switching back to SSS.

- Given present technology, interval meters are the only means by which actual customer cost and consumption data may be transmitted to the supplier.

- MIST Meter refers to "*Metering Inside the Settlement Timeframe*" and means interval meters from which data are obtained and validated within a designated settlement timeframe.

- MOST Meter refers to "*Metering Outside the Settlement Timeframe*" and means interval meters from which data are only available outside the designated settlement timeframe.

Implementation Issues

There are several issues related to the widespread deployment of interval meters which must be considered before adopting the final Distribution System Code (DSC). Some of the issues related to this topic are listed below:

- **Distributor Expenditures and Costs:** The issue of who needs to be addressed, as many distributors may not be able to afford the cost of widespread deployment of interval metering and will not derive financial benefit from their installation and use.

- **Available Meter Inventory:** While distributors may not stock quantities of interval meters, the group agreed that the rate of consumer requests to move to interval metering probably will not be overwhelming.

- **Meter Data Communication and Reading Issues:** It is very important that guidelines on communication equipment and protocol be prescribed and followed for all installations to ensure uninterrupted consistent interrogation of Interval Metering systems.

- **Access to Meters:** Distributors must have access to MOST meters; alternatively all inside or restricted access meters will be MIST meters.

- **Data Management Systems:** Systems will need to be able to manage data from additional customer sites. If distributors do not have the proper systems in place, they may need to consider outsourcing to meet additional Data Management requirements.

- **Time Frame:** Long lead times will be required if large numbers of requests for interval metering are received.

Summary of Discussion

The discussion focused on customer choice, guidelines or codes, past practice and the impact on all parties involved. It was recognized that the customer should have as many choices as practical, and that the greatest potential for energy savings may be achieved when customers have the ability to participate in the open market. The subgroup considered the impact on the consumer and the distributor and the importance of having guidelines to ensure consistency, flexibility and effective installation.

It was generally agreed that interval metering should be available to all customers, but there should be a guideline regarding its availability from distributors. The MDC proposed threshold of 50 kW demand or average monthly consumption of 12,500 kWh initially seemed to be a suitable threshold. Should competitive meter services become available after market opening, the customer probably would have more choices available and possibly no threshold under the services of a meter service provider (MSP).

The group agreed that the option for customers to switch back to standard supply service should be available to all customers, provided they meet all requirements as set forth by the DSC. These mobility requirements should address costing issues.

The group also discussed the possibility of distributors offering interval metering to all customers, including low volume users. Another SOR discusses distributors' obligations and options with regard to offering interval metering to customers.

The group also identified issues surrounding customers that have installed energy management or load shifting technologies to take advantage of time of use rates. Those customers may be interested in taking advantage of hourly pricing through interval metering. In order to facilitate continued deployment of this type of efficient end use technologies, all customers should have the option to be provided with interval metering.

It was noted that there will be considerable lead times required if a large number of requests for interval metering are received. Distributors may need to expand their internal systems, and lead times of 12 to 24 months could be expected.

Customers that request interval metering should be responsible for the cost; this will tend to limit frivolous requests and limit the overall volume of requests to a manageable level. It also will ensure that customers that do not request interval metering do not pay for the options exercised by others.

The cost of a single phase MOST meter is estimated to be approximately $300 per unit.

Recommendation

Option 1 is recommended. All customers below 1 MW should have the option of requesting interval metering, but only in accordance with the following criteria:

1. Customers that request interval metering will be responsible costs as described in a parallel Summary of Recommendation entitled, "*Interval Metering – Customer Responsibilities.*"

2. The schedule for implementation of this recommendation shall recognize the timelines required for widespread deployment of interval metering (up to 24 months may be required to fulfill customer requests for interval metering).

3. The decision about which type of meter to install, either MIST or MOST, shall rest with the distributor. The group anticipates that distributors will choose to install MOST meters for residential customers.

4. The communication system utilized for MIST meters shall be developed in accordance with distributor requirements.

5. Installation of a communication line is mandatory in the case of inside or restricted access meters and should be installed at the customer's expense.

Voter Summary

Unanimous.

Dissenting Opinions

None.

5.4 INTERVAL METERING – CUSTOMER RESPONSIBILITIES

[FINALIZED: MARCH 9, 2000]

Issue Statement

A separate SOR addressed customer options for interval metering and recommended that all customers be given the choice of interval metering. This SOR deals with the question of customer responsibility for the cost of interval metering and addresses the next step of allowing customer choice. The issue is:

> Should the customer be responsible for the costs of installation, maintenance and communications of interval meters?

Options

1. Customers should be responsible for **all** costs related to interval metering.

2. Customers should be responsible for **all incremental** costs related to interval metering, with the standard set by the distributor.

3. The **distributor** should cover **all** costs related to interval metering, and recover these costs through rates.

Background Information

The following pieces of information were considered by the subgroup when developing this recommendation:

- All recommendations assume that metering would be a non-contestable service.

- There is no common practice among utilities at this time with regard to customer responsibility and interval meters; some Ontario distributors pay for meters and communications, other distributors pay only for communications, and still other distributors seem to have a standard that is not always consistently applied.

- Under the guidelines of the Market Design Committee report that assumed a contestable market for metering services, retailers could introduce the advantages of interval meters to the customer. The retailer then would be responsible for the meter and could default these responsibilities back to the distributor or have them covered through approved Meter Service Providers. The benefit of interval metering was assumed to be to the customer and, therefore, the customer would be responsible for the costs.

- The Market Rules do not go into detail on retail metering, but they are quite clear on the subject of wholesale metering. According to the Market Rules, the customer is responsible for all wholesale market metering costs.

- The Retail Settlement Code (RSC) is clear with regard to the issues of responsibilities of retailers during the Settlement Process, but the RSC does not touch on responsibility for metering.

<u>Implementation Issues</u>

Billing and Collection Concerns

The Market Rules and the Retail Settlement Code are fairly clear on the responsibility of the Retailer to choose one of the following three options:

1. An agreement with the distributor to maintain low risk for the retailer.

2. The retailer may enter into an agreement with the distributor in which both parties share partial risk.

3. The retailer may assume all risk and default information back to the distributor.

Meter Sales and Service

Determining who will set the price for metering equipment and then service equipment owned by the customer may be difficult.

Ownership Issue

It is not entirely clear who should own the interval meter, the customer or the distributor. Even if the customer pays for the meter, it is not entirely clear that the customer owns the meter.

New Customer versus Existing Customer

There should be no difference in treatment between an existing customer or a new customer for the distributor.

Stranded Meter Costs

Stranded meter costs should be recoverable.

Timing

If large volumes of customers request interval meters, there may be lengthy lead times to install all of the meters and expand the distributors' systems.

Summary of Discussion

The group considered the reality of multiple customer requests for interval meters at market opening, and the future demand for this option as the new market matures. As with the rest of the issues that surround interval metering, this question opened up more issues that may arise during implementation.

Generally the group agreed that the customers should be responsible for all incremental costs related to interval metering. It was felt that this approach would reduce cross-subsidization of costs between different customer classes and among customers within a class. Large customers that would potentially influence the NSLS or customers that request interval metering should pay the incremental cost of interval metering.

With respect to customers that have mandatory interval metering, the group agreed that mandatory metered customer should also pay for all related costs. The group felt that this was cost is part of doing business, similar to the customer paying for breakers or fuses. It was noted that in the wholesale market, wholesale market participant pays for the cost of metering.

In considering responsibility for the cost of interval metering, the group noted that the distributor has a responsibility to provide basic metering. This led the group to the view that the customer should be responsible for incremental costs associated with interval metering beyond basic metering that would be provided by the distributor for that particular customer class.

All related incremental costs related to interval metering should be billed using the same option as the retailer's billing option. The group felt that reverification costs also should be recoverable. Reverification costs could be an incremental cost, depending on the distributor's standard.

Has the DSC recommendation for point of demarcation between utility and customer, in relation to metering and instrument transformers, been decided? It was felt that the demarcation point was at the test block, and therefore the meter will be owned by the distributor. However, because metering is assumed to be non-contestable, ownership is a non-issue. All ownership shall remain with the distributor.

Recommendation

Option 2 is recommended.

1. Customers that request interval metering should be responsible for all incremental costs related to interval metering above the distributor's standard offering.

2. Within the context of this recommendation “interval costs” refer to:
    - Cost of the interval meter.
    - All additional installation costs associated with the interval meter.
    - Ongoing maintenance, including allowance for meter failure.
    - Verification and reverification of the meter.
    - Installation and ongoing provision of communication line or communication link.
    - Cost of metering made redundant by the customer requesting interval metering.
    - “Costs” do not include initial acquisition of MV – 90 or equivalent software and associated training.

3. The customer is responsible for incremental costs associated with interval metering, regardless of whether the interval metering is installed at the request of the customer or in compliance with a mandatory threshold specified in the DSC.

4. Ownership of the meter shall remain with the distributor.

Voter Summary

Unanimous.

Dissenting Opinions

None.

5.5 METERING REQUIREMENTS FOR EMBEDDED GENERATORS

[FINALIZED: MARCH 15, 2000]

Issue Statement

The Retail Settlements Code Task Force recommended that all embedded generators have a four-quadrant interval meter and do settlements according to hourly pricing. The IMO already has established criteria and standards for generators who are market participants. The issue is:

> What rules/standards should govern the metering requirements for embedded generators who are connected at distribution voltage but are not market participants in the IMO controlled grid?

Options

1. Utilize the IMO wholesale standard for metering of all embedded generators.
2. Require all embedded generators to have four-quadrant interval metering with an accuracy class similar to distribution system customers.
3. Require all embedded generators to have four-quadrant interval metering using existing hardware.
4. Require all embedded generators to phase in the use of four-quadrant interval meters within 12 months of the issue of the Distribution System Code and test installations and apply a correction factor where the existing hardware installation (instrument transformers) does not meet Measurement Canada standards.

Background

Measurement standards for the sale of electricity are subject to regulation by the *Electricity and Gas Inspection Act*. The *Act* identifies that meters require verification and sealing according to Measurement Canada Standards.

The Retail Settlements Code (SG 3-24) recommends that four-quadrant interval meters be installed for all embedded generators and, in discussion notes, that retail embedded generators should be treated the same as retail customers.

IMO market participants are required to have dedicated 0.3% accuracy class Instrument Transformers, redundant metering and remote interrogation of the metering.

Most generators embedded in the distribution system (current estimates place this number at 200) are small, and many were established in the early 1900's. Although output meters are installed for settlement purposes, the accuracy of Instrument Transformers may not be established and remote interrogation may not be currently available.

Settlement of energy flow at the distribution level is the mandate of the local distributor and to be performed in accordance with the Retail Settlements Code. The RSC specifies the equations and methods to be used to complete the settlement process.

Implementation Issues

Is it appropriate to require embedded generators to meet Wholesale Standards (IMO market participation) if supplying solely at the distribution level?

The wholesale standard, as outlined in Chapter 6 of the Market Rules, clearly identifies the metering requirements for any generator that is an IMO-controlled grid market participant. These requirements are onerous for small generators, necessitating improved accuracy class Instrument Transformers, Main and Redundant Meters with 5 minute interval recorders and remote interrogation. This equipment imposes a significant expense (in excess of $100,000 per installation), and may bankrupt some generation sources.

At the distribution level, the accuracy of monitored supply traditionally has been at a lower level, with all customers covering Unaccounted for Losses as a proportion of their "Hydro" costs. Under Retail Settlements, Unaccounted for Losses will continue to be a shared cost by all customers and as such it would seem appropriate that the metering standard for embedded generation should mirror the requirements for any other customer at the distribution level.

Where existing embedded generators install four-quadrant interval metering to satisfy the RSC, should they be required to upgrade the instrument transformers to a specified accuracy class?

Measurement Canada believes that only current transformers of accuracy classes 0.3 and 0.6 and voltage transformers of 0.3, 0.6 and 1.2 can be used for revenue metering. Where installations currently exist that do not conform to this standard, the question of how to cover off the potential inaccuracy of the metered supply needs to be addressed. This could be done in a number of ways, including:

- Testing the existing transformers (reference CSA CAN3-C13-M83).
- Applying a standard penalty to the site settlement losses to account for the unproven accuracy rating.

- Mandating that new transformers be installed.

- Ignoring the inaccuracy and deeming it statistically insignificant (value, quantity).

Testing of the transformers to *CSA CAN3-C13-M83* would require shutdown of units, removal of transformers to a certified meter shop for testing and may yet result in the application of penalties if they fall outside of the required accuracy ratings.

A standard loss factor could be applied to the metered generation until such time as the instrument transformers at the facility are changed to a Measurements Canada approved unit. Depending on the value of the loss factor, this could drive an embedded generator to make the change within an appropriate period of time.

Embedded Generators could be required to install Measurements Canada approved Instrument Transformers. This issue raises the question of value gained versus expense incurred for small generators.

Due to the size of the embedded generator, the distributor could choose to ignore the accuracy of the meter reading as statistically insignificant in the settlement process. Although this sounds contrary to good business practice, the impact of a potential point percentage meter error for a 1 MW generator may not be statistically significant compared to the overall U.F.L. in the distribution system. This may also be applicable for distributors to consider with respect to the other metering points across the system in order to avoid discrimination.

It would seem appropriate that for new generation, the Measurements Canada standard should be applied. For existing generation that cannot establish the accuracy class, a 1% penalty could be applied to the site loss factor to cover any potential metering error. This loss factor would be removed once Measurements Canada standards were achieved.

Alternatively the estimated cost of in-situ testing to determine the accuracy of installations likely will be reduced by the current development and approval of new test procedures and equipment. This process is being developed for use at the wholesale level, but it can be adapted to lower voltage applications. Thus, the preference would be to test the installation and apply a correction factor.

As the Distribution System Code will not be issued for several months, is it reasonable to expect compliance with the metering standard by market opening?

The ability of embedded generators to meet the four-quadrant requirement by November 1, 2000 is limited by the time from when the required standard will be confirmed, the ability of manufacturers to satisfy the hardware demand and the ability of the embedded generator to install the equipment. As the cost of the equipment and installation timing may be critical factors in the decision process to proceed, embedded generators should be allowed a 12-month period to comply with the standard, from the date of issue of the DSC.

Should the embedded generator be required to provide remote interrogation of the meter reading and at what frequency?

The RSC recommends that hourly pricing be used for settlement at the distribution level. The RSC also recommends that interval metering should be read weekly to allow for validation, editing and estimating by noon on the fourth business day after the reading day.

Where embedded generators have communication systems in place, these systems should be adapted to allow for remote reading of meter information to facilitate the distributors settlement process. Hardware currently exists to allow for shared use of telephone lines to accomplish this. Where telephone communication is not available, the distributor and embedded generator must agree on the process to transfer metering information and if this results in extra cost for the distributor, an appropriate charge should be applied.

Who pays for and who owns the meter?

The practice of charging the “customer” for meter and meter installation varies widely across the Province. Traditionally, embedded generators have been required to supply their own meter for settlement purposes. This practice should continue as the benefit of having the meter resides fully with the generator; thus, the generator pays and the generator owns.

How should the embedded generator have access to the meter information?

In many installations, the interval data is only available for the settlement process, but a totalizer provides data to the embedded generator. The group did not consider this as an issue when pricing was established on a MWh rate charge basis. With a move in the market to time of use rates, there will be a need for the generator to confirm the hourly values that the distributor is settling. Meter data should be available to the embedded generator in read only format.

At what point should the meter be installed?

The preference for any system is to have the settlement occur at point of delivery. In an electrical system, there are some practical limitations to making this happen. In general, Instrument Transformers can be placed on the high side of the output transformer but are more commonly situated on the low side. When the meter reading point is on the high side of the transformer, the loss factor for the site will be a function of the line distance from the meter point to the connection point with the distributor. When the meter is on the low side of the Transformer, a site loss factor (covering transformation) will be applied consistent with the recommendations of the Retail Settlements Code.

Estimated Cost of Four Quadrant Interval Metering

The cost of four quadrant metering is estimated as follows:

44kV installations	meter - $5,000 instrument transformers - $50,000 installation - $20,000 Total – approx $75,000 ***
4.16kV installations	meter - $5,000 instrument transformers - $15,000 installation - $5,000 Total – approx $25,000 ***
Single Phase Installations	approx $1,000

*** Installation costs can be significantly higher if switch gear needs to be replaced, in which case, the cost could be in the hundreds of thousands of dollars. There may also be additional expense for telecommunications.

Summary of Discussion

The group felt that the DSC should clarify the recommendation of the RSC, in that four-quadrant interval metering should be mandatory for all embedded generators that sell power from the facility. When there is no impact on the external distribution system, such as load displacement, there should be no mandated requirement for a four-quadrant interval meter.

With respect to the cost impact of installing new hardware, the group discussed whether the need to upgrade instrument transformers should occur coincidentally with the installation of the new meter. If the meter was already installed, the hardware should only be upgraded when the meter is due for reverification.

The group was of the opinion that where the installation does not meet Measurement Canada standards, the installation, including instrument transformers, should be tested and a correction factor applied.

The group raised the issue of dispute resolution, but this topic was considered adequately covered in the Electricity and Gas Regulation Act.

One member raised a question regarding how the distributor would know which metering arrangement was in force at a particular site. The metering arrangement should be included in either the connection agreement, settlement documentation, or the generator's license.

In instances in which an embedded generator sells power from one point but consumes station service or back-up supply through another point on the same distribution system, the issue of gross charge versus net charge occurs. This issue is being resolved at the Transmission level and the precedence established there should prevail at the distribution level.

Inspection of complex metering installations should be performed on a routine basis (e.g., annually) and include cross-phase readings to check voltage and current levels against meter data, multipliers, etc.

Recommendation

Option 4 is recommended.

1. All licensed embedded generators who sell power for use in the distribution system should be required to have a four-quadrant interval meter installed for hourly settlement within 12 months from the date of issue of the Distribution System Code.

2. Where the metering installation does not conform to Measurement Canada standards (accuracy class of instrument transformers cannot be confirmed), the meter installation, including instrument transformers, shall be tested and a correction factor shall be applied until such time as the metering installation conforms to standards.

3. The preferred location for the metering point is the point of supply. Where this is not practical, loss factors will be applied to the generation output in accordance with the recommendations of the Retail Settlement Code.

4. The embedded eenerator must provide the technical details of the metering installation to the distributor for settlement purposes.

5. All new embedded generation installations (built after the issue of the Distribution System Code) shall have four-quadrant interval metering and instrument transformers with the same Measurement Canada accuracy class as distribution load customers.

6. Customers that have unlicensed generation capability, (back-up, co-generation or generation for load displacement that is not retailed) shall be metered in the same manner as other distribution customers.

7. The connection agreement between the embedded generator and the distributor shall identify the interval at which the metering shall be inspected.

8. The generator shall install and own its metering equipment.

Voter Summary

Unanimous.

Dissenting Opinions

None.

5.6 METER READING CYCLES (INTERVAL AND NON-INTERVAL METERS)

[FINALIZED: FEBRUARY 29, 2000]

Issue Statement

The group discussed and considered when and where a standard meter reading schedule was required. Discussions focused on distributor choice, guidelines, past practice and impact on all parties. The issue is:

> How should the Distribution System Code specify standard metering reading cycles?

Options

1. The DSC should be silent on the issue of meter reading cycles and allow distributors to read meters according to their existing schedules.

2. The meter reading cycles specified in the Retail Settlement Code are sufficient and no additional criteria should be specified in the DSC.

3. The customer shall decide when and how the meter is to be read.

4. The DSC should specify compulsory standard meter reading cycles.

Background Information

At the present time, there is no standard meter reading cycle; all utilities utilize their own schedule. Distributors presently establish their own meter reading cycles according to local conditions. Distributors typically read meters on a monthly, bi-monthly or quarterly basis. Remote or seasonal customers may be read once per year. Distributors must also contend with hard to read installations such as indoor residential and inaccessible meters. Distributors may not have the software and hardware available to read all types of meters remotely.

The Market Rules do not address retail meters, but are quite clear with regard to wholesale meters. In addition, the Retail Settlement Code is very clear on meter reading schedules for MIST and MOST meters.

For clarity within this SOR, definitions from the Draft Retail Settlement Code are repeated below:

- MIST Meter; refers to "*Metering Inside the Settlement Timeframe*" and means interval meters from which data are obtained and validated within a designated settlement timeframe.

- MOST Meter; refers to "*Metering Outside the Settlement Timeframe*" and means interval meters from which data are only available outside the designated settlement timeframe.

Implementation Issues

Imposing a standard meter reading cycle for all MOST and non-interval meters could increase costs for some distributors, particularly in remote, seasonal or hard to read installations, without any discernable improvement to the settlement system or end use customer.

Summary of Discussion

The Retail Settlement Code specifies that distributors shall read all MIST meters at least once during a weekly interval (RSC Section 5.2).

The Retail Settlement Code allows distributors to establish their own meter reading cycles for MOST meters (RSC Section 5.2). The RSC provides guidance on dealing with variations due to differences in meter reading cycles (RSC Section 3.5). It is understood that there is no settlement reason for a standard meter reading cycle for MOST meters. The group considered that, in terms of meter reading cycles, non-interval meters and MOST meters can be treated the same.

In establishing its own meter reading schedule for MOST and non-interval meters, the distributor must not discriminate between Standard Supply Service (SSS) customers, retailers and customers of retailers or the customers of the distributor's retail affiliate.

It is anticipated that many utilities will utilize third party products and services for retail settlement. If standard meter reading cycles will improve the efficiency of the settlement process, a trend towards standardization will emerge due to the influence of third party service providers without the need for regulation.

It was generally agreed that distributors should follow the guidance provided by the Retail Settlement Code. There is need to specifically mention non-interval meters since the RSC specifies meter reading cycles for MIST and MOST meters but is silent on non-interval meters.

Recommendation

A combination of recommendations 1 and 2 is recommended.

Distributors shall establish non-discriminatory meter reading cycles as specified within the Retail Settlement Code. This will entail at least weekly reads for MIST meters and per distributor practice for MOST and non-interval meters.

Voter Summary

Unanimous.

Dissenting Opinions

None.

5.7 METER DISPUTE PROCESS

[FINALIZED: FEBRUARY 29, 2000]

Issue Statement

Distributors will be responsible for meter installation and meter reading. In these activities, there are bound to be meter disputes. This SOR address distributor rights and obligations of distributors and customers regarding meter activities. The issue is:

> What rights and obligations do distributors and customers have with regard to meter disputes?

Options

1. Allow each distributor to decide on the level of service they will provide to the customers in their licensed service area.

2. Prescribe a minimum level of service that all customers across Ontario can expect.

3. Call in an independent third party to validate a distributor's practices.

Background

Meter and billing disputes may occur in the act of supplying electricity. These will be in the nature of questioning the reading, the amount of consumption, the rate(s) charged for the commodity or the accuracy of the reading. Possible dispute scenarios that may arise are as follows.

Meter Reading

A dispute over a meter read has four courses of action possible:
- Re-read by distributor / meter reading company.
- Customer reads meter and phones in to distributor.
- Customer reads and marks card and mails or drops off to distributor.
- Electronic reading / data transfer.

Consumption

- Distributor (meter owner) can make use of historical data to validate the consumption and therefore validate the read to themselves and to the customer.
- On site parallel metering to justify the registration.

Rates

- Distributors will be able reference the charges as per notification of the monthly weighted charge from the IMO.
- Distributor references retailer rates
- A true-up between what was charged and what should have been charged occurs.

Accuracy

- Distributor can show the certificate and confirm the AMV / Measurement Canada seal is intact to protect the integrity of the meter.

Implementation Issues

- Geographical restrictions for distributors will affect the ability of the distributor to provide the services due to distance and/or expense involved in gathering the information.

- Reading an electric meter may be confusing to untrained persons. Therefore, readings taken by customers are not considered reliable.

- Some measures need to be in place to minimize frivolous or unfounded disputes. For example, how many times does the distributor need to react in a standard way for a particular customer? How many free disputes per year does a customer need to be able to make before these complaints are considered as being unfounded?

Summary of Discussion

Regarding the subject of guarding against frivolous or unfounded disputes, the group considered establishing a criteria whereby a customer would be allowed a specified number of disputes at no cost within a given time frame. However, concern was expressed that this would not address the issue of minimizing unfounded disputes. It was agreed that customers should be obligated to validate the problem(s) they perceive. It was therefore proposed that distributors be allowed to charge a fair an reasonable meter dispute fee which would be reimbursed or not charged in the event that the meter, installation, or distributor were found to be in error.

At the Task Force level, it was noted that customer charges established by a distributor are subject to OEB review and approval.

Retailers should have access to the same meter dispute process as customers and be assessed the same fair and reasonable distributor meter dispute charge as noted above.

The Measurement Canada dispute process is available to distributors when they are not able to satisfy customer concerns with respect to the bill and how it is derived. Customers have access to Measurement Canada resources per the *Electricity & Gas Inspection Act* and associated regulations.

Recommendation

Option 2 is recommended.

1. The DSC should obligate distributors to respond to customer and retailer metering disputes.

2. The DSC should empower distributors to establish a fair and reasonable charge for costs associated with resolution of customer and retailer metering disputes.

3. If the complaint is substantiated the charge will not be applied to the customer or retailer, if not the customer will pay the established cost.

The above does not preclude the distributor from seeking the help of "qualified" independent organizations such as Measurement Canada or an accredited meter verifier at anytime in the process.

Voter Summary

Unanimous.

Dissenting Opinions

None.

5.8 LIABILITY AND SETTLEMENT ISSUES IN THE CASE OF METERING ISSUES

[FINALIZED: MARCH 9, 2000]

Issue Statement

The issue is:

> What are a distributor's rights and obligations regarding liability and settlement issues in the case of meter errors.

Options

1. The DSC provide no comment; the provisions of other codes and existing legislation are adequate and no additional DSC requirements are required.

2. The DSC impose criteria regarding liability and settlement issues in the case of meter errors in addition to those specified in the Retail Settlement Code.

Background Information

Retail Settlement Code

The Retail Settlement Code, Section 7.7, provides the following direction regarding billing errors:

Over Billing

> Where a billing error, from any cause, has resulted in a consumer or retailer being over billed, and where Measurement Canada has not become involved in the dispute, a distributor will credit a consumer or retailer with the amount erroneously billed. The credit a distributor remits to the appropriate parties shall be the amount erroneously billed up to a six year period.

Under Billing

> Where a billing error, from any cause, has resulted in a consumer or retailer being under billed, and where Measurement Canada has not become involved in the dispute, a distributor shall charge a customer or retailer with the amount that was not previously billed. In the case of an individual residential consumer who is not responsible for the error, the allowable period of time for which the consumer may be

charged is two years. For non-residential consumers or for instances of willful damage, the relevant time period is the duration of the defect.

Customer Notification

The entity billing a consumer, whether a distributor or a retailer, is responsible for advising the consumer of any meter error and its magnitude and of their rights and obligations under the Electricity and Gas Inspection Act (Canada). The billing party is also responsible for subsequently settling actual payment differences with the consumer or retailer as described above.

Electricity and Gas Inspection Act

Federal legislation specifies somewhat different criteria than those described in the Retail Settlement Code. In cases where Measurement Canada has become involved in the dispute, the provisions of the *Electricity & Gas Inspection Act* and associated regulations will apply

The *Electricity & Gas Inspection Act* indicates that the customer or distributor, as the case may be, is liable for the amount either over or under billed due to a metering error. The maximum period of time during which the error is assumed to have existed varies according to the circumstances, but it can be as long as the meter (or related apparatus) was in service. The provisions of the *Act* are consistent regardless of whether the error resulted in an over or under billing and does not differentiate between residential and commercial/industrial customers.

Case Law

There have been court cases surrounding metering errors that influence the approach utilities adopt when dealing with metering errors.

Implementation Issues

The Retail Settlement Code approximates the policies and practices previously described in the Standard Application of Rates (SAR) and, therefore, is similar to existing utility practice with one important exception. In the case of under billing of non-residential customers, the SAR specified a maximum period of 6 years for the utility to charge the customer for the amount in error. The RSC specifies no time limit; the distributor shall charge for the period of time that the defect existed.

While the RSC provides adequate consideration to distributors and residential customers, non-residential customers may question the fairness of the RSC provisions. The distributor is obligated to refund an over billing to a limit of six years, yet there is no time limit on the collection of an under billing error. The RSC requires that the distributor charge a non-residential customer for the full time period of a billing or metering defect. Experience has shown that some customers will resist or refuse to pay for an error that has been in place for an unreasonably long time.

Although the distributor may charge the customer the full amount of the under billing, there must be room for negotiation with customers regarding the actual amount recovered or weighing the cost to pursue a small under billing.

Summary of Discussion

The RSC provisions are sufficiently broad in that a "billing error, from any cause" includes a metering equipment error, meter reading error or application of an incorrect multiplier.

The provisions of the RSC provides an economic incentive for the distributor to be diligent in preventing / managing meter errors in that the distributor is responsible for refunding or charging for any metering error. In the event that retail metering becomes a contestable service, this issue will need to be revisited and new code criteria developed (e.g., Metering Code).

Recommendation

Option 1 is recommended.

1. No additional DSC criteria regarding distributor liability and settlement in the case of meter errors is required.

2. The DSC should allow distributors flexibility to negotiate terms of payment as well as to assess the feasibility of collecting an amount under billed.

3. Despite the provisions of the RSC and the DSC, customers and distributors both have recourse under the *Electricity & Gas Inspection Act*.

Voter Summary

Unanimous.

Dissenting Opinions

None.

5.9 LONG TERM STORAGE OF METER DATA

[FINALIZED: MARCH 15, 2000]

Issue Statement

This SOR addresses the issue of long-term storage of meter data (i.e., consumption information). The issue is:

> Should the DSC require distributors to store customer consumption information for any period of time?

Options

1. The DSC make no comment - Measurements Canada regulations as covered in Sections 16 and 17 of the Electricity & Gas Inspection Act and Section 11 of the Electricity & Gas Inspection Regulations are sufficient.

2. The DSC specify that meter data is to be archived by the distributor for a minimum of 7 years.

Background

Measurement Canada, under the *Electricity & Gas Inspection Act* has jurisdiction concerning the long-term storage of meter data. Under current Measurement Canada regulations, meter data is required (according to Measurement Canada interpretation) to be archived for the life of the meter plus one-year. Currently, meters can have a service life of over 25 years. Under current practices many distributors retain meter billing data for 5 to 7 years. This shorter period for retention of data relates to the 6-year maximum period for correction of over or under billing specified in the former Standard Application of Rates.

The primary reason to retain this historical data is to provide historical information to assist in resolution of billing or metering disputes.

Implementation Issues

The prospect of storing, maintaining and updating meter information for up to 25 years is a daunting task. The long time frames raise a number of issues, including:

- In what format should the data to be stored?

- What software should be used to store the data and should the data be updated and reformatted if a different software package is used in the future?

- If data is to updated in the future, how is the cost of the upgrade to be recovered?
- Depending on the storage medium (e.g., CD-ROM, DVD), will hardware be available to access the data?
- Personnel issues: who is going to have the necessary skills to retrieve the data in 5, 10 or 15 years?

In addition, there is a discrepancy between interpretation of federal regulation and current utility practice.

Summary of Discussion

Metering subgroup members discussed existing Measurement Canada requirements and recognized that federal legislation cannot be superceded by a provincial Distribution System Code. On the other hand, it did not seem appropriate to include in the DSC a federal requirement that is perceived to be impractical and of limited value to the Ontario market.

Section 11 of the Retail Settlement Code, which deals with access to consumer information, provides detailed direction regarding provision of current and historical consumption information and details of the metering installation to consumers and other parties designated by the consumer. Section 11.13 indicates that any of this information that varies from one billing period to another is to be provided for 24 billing periods <u>if the distributor's standard practice is to keep this many billing periods readily accessible</u>. If fewer than 24 billing periods are readily accessible, the distributor is to provide no less than 12 months worth of information. The information to be provided according to this section of the RSC is similar to that specified in federal regulation.

Section 7.7 of the Retail Settlement Code deals with billing errors and stipulates that if Measurement Canada has not been called in, the distributor shall rebate the consumer (or retailer) in the event of an over-billing to a limit of 6 years. In the case of an under-billing the distributor is directed to charge the consumer for the amount under-billed up to a limit of 2 years for residential consumers and for a period of time equal to the duration of the defect for non-residential consumers.

To facilitate resolution of billing errors and provision of current and historic consumption information, as well as information on the metering installation, the distributor will need to retain information for a period of time considerably less than that required by Measurement Canada.

Members noted that new technologies have improved data storage capabilities; however, maintaining voluminous data in a format and medium that can be accessed is nonetheless a difficult task with limited usefulness if required for the life of the meter.

The provisions of the Retail Settlement Code appear to describe realistic expectations for the Ontario market.

Members noted that to address the apparent difference between federal regulations and the practical needs of the Ontario market, a general condition such as the following could be included in the DSC:

> Nothing in this Code shall affect the obligation of the distributor to comply with all applicable federal metering requirements provided that, where this Code or other conditions of licensure prescribe a higher standard than that prescribed in the federal metering requirements, the distributor shall comply with the higher standard.

Task Force members concluded that the issue of retention of records is sufficiently covered in federal legislation and other OEB Codes.

Recommendation

Option 1 is recommended. No DSC criteria on the subject of long term storage of meter data should be imposed.

Voter Summary

Unanimous.

Dissenting Opinion

None.

5.10 PROVISION OF METERING INFORMATION TO RETAILERS AND CUSTOMERS

[FINALIZED: MARCH 9, 2000]

Issue Statement

The provision of current metering type information to both retailers and customers is an important issue in a competitive retail market. Specific metering information may be made available to both retailers and customers in categories that deal with the metering equipment installed and billing information. Provision of meter information is addressed in the Retail Settlement Code, section 11.3. The issue is:

> What distributor obligations regarding provision of current metering information to retailers and customers should be specified in the Distribution System Code?

Options

1. Distributors should develop their own information standards.

2. Distributors should follow a common standard to be used by all distributors.

3. Distributors should a follow a minimum common standard plus provide any additional information unique to the distributor.

4. No additional DSC provisions are required.

Background Information

The Retail Settlement Code (RSC) provides some guidance on the rights of consumers and retailers to access current and historical usage information. The provision of this information by the distributor to retailers must have authorization by the customer and follow a set schedule for meter reading and subsequent posting. Customers with remotely read interval metering will be handled differently than manually read interval and non-interval metered customers. Customers with remotely read interval meters or non-remotely read interval meters shall have access to the metered data under the same terms and conditions as for the retailer. Manually read customers, which are non-interval metered, shall have access to usage data either through direct access to the meter or in a form which is presented on the bill.

Implementation Issues

Some information that is identified in the Retail Settlement Code, Section 11, may not be readily available by all distributors, such as average or distribution loss factor for billing period. The RSC, in a footnote, allows distribution loss factor, if it is constant across billing periods, to be provided separately rather than attached to each customer record.

Summary of Discussion

The group reviewed the metering information that must be provided under section 11.3 of the November 12, 1999 draft RSC. The subgroup noted that the metering information listed in the RSC is complete, with one exception. Current and potential transformer ratios should be provided in addition to the meter information.

The final version of the RSC, issued on February 28, 2000, addressed this issue and added the following phrase: "all relevant multipliers necessary to calculate a bill, including but not limited to relevant CT and PT ratios."

The opinion was expressed that a distributor should be allowed to recover costs incurred in providing the information mentioned above.

Recommendation

Option 4 is recommended.

1. No additional requirements to provide metering information to customers or retailers authorized by the customer need to be identified in the DSC.

2. Distributors should be allowed to establish fair and reasonable charges to recover costs incurred in providing metering information specified in section 11.3 of the RSC.

Voter Summary

Unanimous.

Dissenting Opinions

None.

5.11 VALIDATION, ESTIMATION AND EDITING OF METERING DATA

[FINALIZED: MARCH 15, 2000]

Issue Statement

Validating, estimating and editing (VEE) is the process used to validate, estimate and edit raw metering data to produce final metering data or to replicate missing metering data for settlement purposes. The issue is:

> What procedures will be used to validate interval data, estimate interval data, and edit interval data in the deregulated marketplace?

Options

1. Develop and implement standard Validation, Estimating and Editing (VEE) procedures for all distributors and Meter Data Management Agents (MDMA) performing meter reading activities, similar to IMO guidelines for wholesale metering.

2. Require distributors to document and implement fair and reasonable VEE practices in accordance with local practices. Distributors will have the option of implementing different processes for interval and non-interval meters. Blends of documented processes (i.e., standard interval data VEE procedures) and local practices will be permitted, provided that there is some assurance that data has been checked for correctness.

3. Allow distributors to maintain local VEE practices.

Background

Distributors employ various means to collect interval data, including utilizing a variety of software packages; there are no standard data management practices. Currently, a standard does not exist to ensure consistency, fairness, and accuracy, especially when multiple retailers, Meter Service Providers (MSP), or MDMAs serve Metered Market Participants (MMP).

Definitions

MIST Meter refers to "*Metering Inside the Settlement Timeframe*" and means interval meters from which data are obtained and validated within a designated settlement timeframe.

MOST Meter refers to "*Metering Outside the Settlement Timeframe*" and means interval meters from which data are only available outside the designated settlement timeframe.

Validation, Estimating and Editing (VEE)

- *Validation* refers to a process of comparing collected meter data and its characteristics against predefined constant limits and checking the meter's event log (if applicable) for indications of a problem with either the instrument transformers or the meter itself.

- *Estimating* refers to the process of substituting provisional meter data in the place of data that failed the predefined validation criteria.
- *Editing* refers to manually changing the data for a particular revenue meter.

Bandwidth refers to the LDC defined tolerance used to flag data for further scrutiny at the stage in the VEE process where a current reading is compared to a reading from an equivalent historical billing period. For example, a 30% bandwidth means that a current reading is either 30% lower or 30% higher than an equivalent historical billing period, and it will be identified by the VEE process as requiring further scrutiny and verification.

Other Jurisdictions

According to the Market Design Committee (MDC) Report, two other jurisdictions have addressed VEE. In the United Kingdom, general guidelines were set forth but significant discretion was allowed on the part of the distributor. In fact, no VEE rules were established for non-interval meters. In California, detailed VEE guidelines were established for interval metering.

Implementation Issues

VEE practices and policies currently vary among distributors. Some distributors have developed complex computer driven automated programs, while others have a less sophisticated VEE process. Imposition of rigid, standard VEE criteria could result in unnecessary effort and cost to validate good data. For instance, imposition of a standard bandwidth could result in excessive quantities of data being rejected and resources wasted verifying perfectly good data. If a standard bandwidth was set higher it could then become a meaningless criterion that would result in acceptance of all data in some areas. The VEE process should reflect the local conditions that prevail within a distributor's service area.

Immediate validation is not possible at older installations where the register on the pulses initiation meter can not be read remotely. The provisions of MV-90, or equivalent software, will influence VEE of MIST data. Given that many utilities are presently tendering for the provision of new billing and settlement software to facilitate the competitive market, it is already too late to establish a standard VEE process. As noted above, it is anticipated that that one VEE process for the province will be highly impractical.

Greater standardization will evolve and may be appropriate as consolidation of distributors occurs.

Summary of Discussion

Committee members expressed concerned about the impact of rigid VEE requirements on smaller utilities or distributors, particularly for non-interval metered accounts. Many distributors set a bandwidth for validation tolerances according to available resources, not necessarily based on an acceptable variation in meter reads. Introduction of a small bandwidth may require some distributors to add staff to check readings. Imposition of rigid, standard VEE criteria could result in unnecessary effort and cost expenditure by distributors to validate good data.

Some group members commented on the appropriateness of the Task Force making recommendations regarding VEE for non-interval meters, since it often was outside of the authority of the metering staff. This lead to the suggestion that non-interval data should be left subject to local validation.

Members of the group also felt that formal validation rules could be set for interval data, but again expressed concern that smaller distributors may have difficulty implementing them. However, based on the revenue generated from these installations and implications regarding net system load shape, a standard approach to data validation estimating and editing is important. The group recognized IMO Specification for VEE of Revenue Metering Data as a potential resource for a common approach to VEE of retail MIST data. The group further recognized that much of the IMO wholesale specification does not apply to retail metering (e.g., redundant metering).

Applicable validation checks specified in the IMO specification include:

Intervals Found versus Intervals Expected
Time Tolerance
Number of Power Outage Intervals
Missing Intervals
Hi Limit on Interval Demand
Hi Limit on Energy
CRC/ROM/RAM Checksum
Meter Clock Overflow
Hardware Reset
Time Reset
Data Overflow on Interval
Comparison to Previous Week
Zero Interval Tolerance
Number of Channels
Changed Device ID

Contributing to the complexity of establishing one province-wide VEE specification for the retail market is the fact that some characteristics are checked across a customer class, while other characteristics are checked against historical information on a per installation basis.

Members expressed the view that customers and retailers should have the right to know how metering data was validated, estimated and edited by the distributor.

Recommendation

Option 2 is recommended. Distributors should be required to document and implement fair and reasonable VEE practices in accordance with local practices. Distributors will have the option of implementing different processes for interval and non-interval meters. Blends of documented processes (i.e., standard interval data VEE procedures) and local practices will be permitted, provided that there is some assurance that data has been checked for correctness.

A sample flowchart of the key elements of the VEE process is included below for illustrative purposes only.

Non-Interval & MOST Data

1. Distributors shall establish VEE criteria according to local practice that is fair and reasonable and provide assurance that correct data is submitted to the settlement process.

2. At a minimum, the VEE process shall compare energy and demand (if applicable) readings from at least one equivalent historical billing period. The distributor shall determine appropriate bandwidths. Other distributor-specified criteria such as correction for weather may be established.

3. Distributors must document and make available their VEE criteria and process for scrutiny by customers, retailers, the OEB, and Measurement Canada.

For MIST Data

1. Distributors shall establish fair and reasonable VEE criteria that provides assurance that correct data is submitted for the settlement process, according to local practice with due consideration of industry standards such as the independent electricity market operator (IEMO) specification, *"Requirements for Validating, Estimating and Editing of Revenue Metering Data"*.In referring to the IEMO specification, it should be noted that installation of redundant and/or check metering is not recommended for the retail market.

2. Distributors must document and make available their VEE criteria and process for scrutiny by customers, retailers, the OEB, and Measurement Canada.

Voter Summary

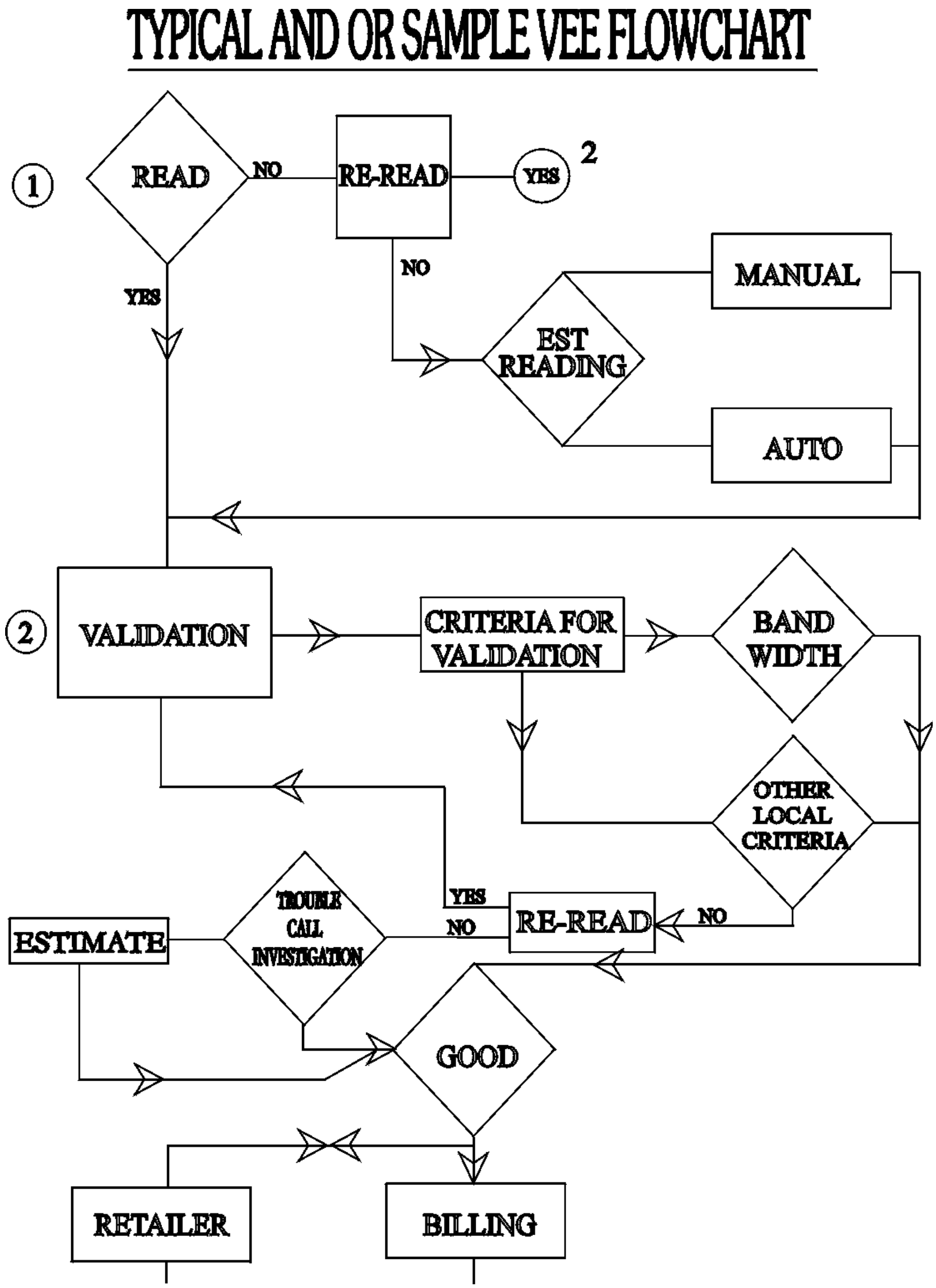
Unanimous.

Dissenting Opinions

None.

Attachment: Appendix A - Illustrative VEE Process Flow Diagram

Appendix A


TYPICAL AND OR SAMPLE VEE FLOWCHART
1
READ
NO
RE-READ
YES
2
NO
YES
MANUAL
EST READING
AUTO
2
VALIDATION
CRITERIA FOR VALIDATION
BAND WIDTH
OTHER LOCAL CRITERIA
YES
NO
RE-READ
NO
ESTIMATE
TROUBLE CALL INVESTIGATION
GOOD
RETAILER
BILLING

5.12 RULES AND PROCESS FOR METER INSTALLATION AND REPLACEMENT

[FINALIZED: MARCH 15, 2000]

Issue Statement

In the past, utilities have installed meters and devices to meet technical and safety standard criteria. This SOR addresses the issue of what rules and/or standards should be applicable for the installation and replacement of metering equipment by distributors in the retail market. The issue is:

> What rules should distributors follow for the installation and replacement of meters and metering equipment?

Options

1. Distributors to develop and follow their own installation standards.
2. Distributors to use Measurement Canada Standards.
3. Distributors to use Measurement Canada Standards as a minimum, with the option of incorporating internal distributor practices.

Background Information

Distributors have been required to meet Measurement Canada standards for equipment and installation details in the past. However, methods used to install equipment vary across the province. Requirements may vary as to what is required by a customer for a utility to provide service, including metering.

Meter replacement typically has been decided by the Measurement Canada seal life of the device. This dictates that the meters will be replaced a six, eight, twelve years or, in the case of seal extension, other intervals.

Some installations may not meet current standards (e.g., colour coding of wiring), and may require some form of grandfathering. Measurement Canada. standards allow for the use of local codes. This must be the colour code used across the distributor with obvious recognition if the code changes. Existing non-standard installations will require grandfathering as rewiring of most installations would require customer power outages. This type of nonconformance does not affect accuracy, but simply is different than specific Measurement Canada requirements.

The IMO standard for wholesale metering exceeds current Measurement Canada standards. Existing Measurement Canada standards in the retail market are sufficient.

Another area to be addressed is one of safety. Safety is not part of Measurement Canada's standards, short of transformer secondaries grounding and the observation of green and white wires.[2] Safety of persons during installation and replacements is subject to the *Occupational Health and Safety Act*.

Implementation Issues

A distributor's ability or inability to meet current MC requirements for existing installations may result in implementation issues. Further explanation is provided in paragraph three of background information.

Summary of Discussion

Generally, the group agrees that installations should meet Measurement Canada standards and that any other practices that may exceed these requirements should be left at the discretion of the distributor. Prescribing more detailed requirements in addition to Measurement Canada standards in the DSC may impact the effectiveness of other standard procedures or service requirements of the distributor.

Recommendation

Option 3 is recommended. Distributors should use Measurement Canada Standards as a minimum, with the option of incorporating internal distributor practices.

Voter Summary

Unanimous.

Dissenting Opinions

None.

[2] Green is recognized as ground, white as neutral by the Ontario Electrical Safety Code.

5.13 INSPECTION OF COMPLEX METERING INSTALLATIONS

[FINALIZED: MARCH 15, 2000]

Issue Statement

In the past, complex metering installations[3] may have undergone some form of inspection during and/or after the initial installation. In order to ensure that installations are correct, and that all customers, distributors and retailers are being treated fairly, a prescribed inspection requirement should be considered. The issue is:

Should complex metering installations be inspected?

Options

1. Distributors are not required inspect installations.
2. Distributors are to have a documented[4] inspection program consistent with the following "Time Table for Inspection Program".
3. Distributors are to have a recognized[5] outside agency provide documented inspections consistent with the following "Time Table for Inspection Program".

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[3] Complex metering installations refers to installations where instrument transformers, test blocks, recorders, pulse duplicators and multiple meters may be employed.

[4] Documentation to include all information as required by CCAC form 636 plus any other documentation to accurately represent the site (including cross-phase readings and calculations) design and peculiarities such as pulse recording equipment, pulse duplication equipment. To be completed on site, audited by qualified person and filed. All persons involved in the installation, inspection and auditing are to be identified.

[5] See implementation issue #3.

Time Table for Inspection Program

<table>
<tr><th>Billing Service Demand</th><th>Maximum time period elapse <u>prior to</u> inspection</th><th>Further inspections</th></tr>
<tr><td>1 Meg & greater</td><td rowspan="3">6 Months (preferably on installation)</td><td rowspan="2">Once during Measurement Canada seal period or upon trouble call</td></tr>
<tr><td>50 kW to <1Meg</td></tr>
<tr><td>< 50 kW</td><td>Not Required</td></tr>
</table>

Background Information

Distributor practices vary across the province, ranging from no formal inspection of installations to regular documented inspection of installations. Measurement Canada has the authority to mandate inspections.

Automated testing equipment has become available, making inspections of complex metering installations more efficient and accurate. This equipment also facilitates an easy documentation process.

Consideration could be given to using an ISO standard, however, an international standard may be restrictive to the direction the province wants to take.

Implementation Issues

1. Some distributors may not have the resources to develop an inspection program (an installation analyzer may cost up to $15,000).

2. Measurement Canada does not have the resources available to meet inspection requests as an outside agency. Inspection standards need to be developed as a minimum to promote continuity of distributor practices.

3. Qualifications need to be developed to label an organization as competent to perform such inspections.

Summary of Discussion

The group agrees that installations should be inspected at regular intervals to verify wiring and ensure equipment performance. A distributor should be given the opportunity to develop an inspection program and to meet minimum requirements of an inspection standard. Economics may promote the use of agencies trained and specialized in the inspection of metering installations.

The self diagnostic abilities of the modern meters increases the probability of early detection of installation failures. These same qualities also provide for simple on-site quick verification of the service.

Discussion also noted that not all single phase transformer rated installations would require inspections due to the nature of the installations. Restrictions could include accessability issues associated with the equipment and low consumption at the installation. For this reason, the “Time Table for Inspection Program” does not require inspection of installations smaller than 50 kW until change of meter or upon trouble call.

Recommendation

Options two is recommended. Distributors should have a documented inspection program (see “Time Table for Inspection Program”).

Voter Summary

Unanimous.

Dissenting Opinions

None.

5.14 QUALIFICATIONS OF METERING PERSONNEL

[FINALIZED: MARCH 15, 2000]

Issue Statement

In the past, distributors have trained or qualified metering employees in a variety of ways. Practices have varied from hands-on training only to institutional programs provided by the employer or an outside agency (such as the former Ontario Hydro Orangeville training school, L&K training package providers and the MEA). These qualification practices should be reviewed to determine what is necessary to provide a safe and accurate metering installation. The issue is:

> What qualifications should metering personnel have?

Options

1. Distributors have no qualification requirements.
2. Distributors have the ability to self determine who/whom is qualified.
3. Distributors be required to meet a minimum prescribed standard for qualifications.
4. Distributors be required to have recognized qualification requirements. An example of formalized training would be the MEA trades training school.

Note: Training documentation should exist to prove who is qualified and for what. This can be through a methodology such as quality documentation.

Background Information

Both the Market Design Committee report and Measurement Canada recognize distributors as being qualified to provide metering services to customers, based on past practice and utility experience.

To date there has been no recognized licensing of Meter Technicians in the trades field, nor has there been any formal requirement to certify metering personnel. The recognition enjoyed by meter technicians in Ontario is a local recognition of the hands-on time and schooling attended by an individual.

Present practices by distributors are widespread. Personnel performing metering activities vary from non-metering personnel who follow diagrams and implied directions such as colour codes to persons who have completed a four year program covering all aspects of the metering field.

Meter personnel do have specific training needs to ensure installation correctness and to address safety issues. Membership in a recognized safety association is typical to most utilities, E&USA, however some of the larger utilities have the resources to provide internal safety programs. The Ministry of Labor is the governing body through the *Occupational Health and Safety Act*.

Measurement Canada ultimately is recognized as the agency to ensure metering installation compliance through field inspections. However, internal inspections and outside agencies[6] are sought in the absence of Measurement Canada inspection.

Implementation Issues

Distributor resources for Safety training and Certification of employees.

A time frame must be given to distributors to show compliance to facilitate the implementation of a training program.

Summary of Discussion

The group agrees that metering personnel do have specific technical and safety training requirements and that distributors are responsible for demonstrating that personnel are qualified. Prescribing technical safety training requirements for metering personnel is essential to promote qualified trades people.

It is recognized that the requirements may pose implementation issues to many distributors. Distributors have different options, full certification for personnel (four year program), partial certification (certification for specific aspects of installation for example linesmen or customer service persons changing single phase meters), or the use of external agencies for the required tasks.

Recommendation

Option 4 is recommended:

1. Distributors should be required to have recognized qualification requirements.

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[6] Typically a neighboring utility with a metering department would be retained to do inspections or perhaps a meter verification organization would be sought. This type of inspection does not have the same weight as Measurement Canada inspection but would be able to satisfy the distributor through a paperwork trail, for example CCAC form 636.

2. Distributors should set forth a work plan to enroll all personnel requiring training in a course that meets the requirements of the tasks to be performed. The time period of the course is to be determined (for example six months).

3. Distributors that have persons that have not completed a recognized training program work on metering systems must have the “task” inspected.

Voter Summary

Unanimous.

Dissenting Opinions

None.

5.15 MINIMUM METERING UNITS FOR THE RETAIL MARKET

[FINALIZED: MARCH 9, 2000]

Issue Statement

Measurement Canada, under the *Electricity & Gas Inspection Act*, prescribes measurement units that can be used for billing. Both the Standard Supply Service (SSS) Code and the Retail Settlement Code (RSC) use 50 kW as a threshold for different billing options. It generally is accepted that 50 kW is an industry standard for identifying an ‘existing’ rate/customer class. The issue is:

> Should specific metering units be set as a minimum requirement for the retail market (e.g., kWh, kW, kVa)?

Options

1. The DSC should not impose requirements for minimum metering units.

2. Requirements for prescriptive minimum metering units should be set.

3. Minimum metering units should be left to the discretion of the distributor.

Background Information

Minimum metering units traditionally have been set by the local utility using Measurement Canada’s approved units for billing (e.g., watt-hours, volt-ampere hour, var hour and joules). As a minimum, kWh has been the standard measure in all customer classes, except for street lighting and other non-metered loads. Common practice prescribes that any customer that is expected to reach a demand of 50 kW or greater, either by estimate or actual measurement, would have a demand meter installed. If a customer, such as a wielding shop for example, is expected to have a power factor of less than 90%, a meter capable of measuring kVa typically would be installed.

Implementation Issues

Implementation issues should not exist or worst case, be very minimal. The vast majority, if not all, distributors will have the necessary experience and/or strategy to carry out minimum metering unit requirements.

Summary of Discussion

In discussion, it was suggested that kWh should be the minimum measured unit, while kW and kVa should be at the discretion of the distributor. The group felt that the distributor has the experience, knowledge and incentive to determine when measurement of kW and kVa is appropriate.

The group generally agreed that demand and/or power factor will play some role in determining distribution rates.

The RSC (Section 4) mentions the possibility of using demand as a way of determining distribution/transmission costs.

Demand and power factor have the greatest impact on the distribution system, compared to a commodity supplier or customer. The group agreed that the distributor should be allowed to set criteria for measurement of demand.

Standard Service Supply Code uses 50 kW demand as a reference point to determine whether an SSS customer is billed on a monthly Weighted Average Price or annually with a true-up.

Electronic meters, industry norm for replacement, have made some units obsolete and new technology may drive the requirements for different units (i.e., pulses – kWh); this should not be considered a minimum, but rather a beneficial exception.

The group expressed the view that the Retail Settlement Code and Measurement Canada Regulations under the *Electricity & Gas Inspection Act* provide sufficient direction regarding units of measurement and that no additional criteria need to be set by the Distribution System Code.

Recommendation

Option 1 is recommended. The DSC should not impose requirements for minimum metering units.

Voter Summary

Unanimous.

Dissenting Opinions

None.