

Subgroup 3: IMO Interface for Retail Settlements Profiling and Settlement MSP/MDMA Interface

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ISSUE STATEMENT (Final)

Global Issue Outline VI:

- How should IMO commodity costs be incorporated into settlement calculations?
- IMO invoices will have charges for a variety of services that will be provided by or billed through the IMO. LDCs will need to translate these charges into cost categories for settlement purposes. Some IMO charges will be defined as commodity electricity charges, others as transmission charges and still others as administrative or IMO membership costs. This decision statement deals only with the commodity portion of the bill.

OPTIONS:

There is significant uncertainty concerning precisely what charges the IMO will include on invoices and what form the charges will take (e.g., hourly, monthly, etc.). There is also little guidance from the Rate Handbook regarding how wholesale costs should be translated into charges to customers and which wholesale costs should be counted as commodity charges in an unbundled bill and which should be counted as non-commodity charges. The distinction between commodity and non-commodity charges is an important one since only commodity services are competitive.

In spite of the uncertainty that remains in this area, there is a need to provide as much guidance as possible in the settlement code regarding how to determine settlement costs for end-use customers and retailers. In light of this uncertainty and the need to move forward, there are two choices to consider:

1. Leave this section of the code essentially blank at this time, indicating that it will be completed when the IMO has more certainty about how costs will be charged and the OEB has provided further guidance on how these charges will be translated into billing determinants.
2. Attempt to narrow the uncertainty as much as possible by eliminating clearly unlikely or untenable options.

BACKGROUND INFORMATION:

As mentioned above, the IMO is unsure of the nature of charges that will be passed on to LDCs. Table 1 summarises the potential charges that the IMO may incorporate in their wholesale settlement statements and the most likely form that these charges will take. The entries in each cell represent current best guesses based on the rating system listed at the top of the table. As seen, the majority of charges will either vary hourly or monthly. A few transmission-related charges may be based on demand and still other charges will be transaction based or involve one-time or annual fees. The list of charges, and the form they may take, are subject to change as the IMO continues to work on determining how best to implement the market rules.

Retail Settlements Code Task Force—Subgroup 3

Legend: 3 = highly likely 1 = highly unlikely 2 = less likely blanks = no chance										
Table 1 IMO Charges to LDCs (and Other Wholesale Customers)										
Service Type	\$/kWh/ hour	\$/kWh/ month	\$/kW or kVa— Coincident	\$/kW or kVa—Non- coincident	Fixed Charge/ Billing Period	Transaction Charge	Rebate/ Debit— Vary by LDC	Annual Fee	One- time Fee	
1. Hourly Energy Settlement Amounts by Registered Facility	3									
2. Physical Bilateral Congestion Management Charge	3									Ch diff de
3. Hourly uplift	3									Me col are
Net Energy Market Settlement	3									
Operating Reserve Uplift	3									
Capacity Reserve Uplift	3									
Congestion Management Uplift	3									
Transmission Rights Uplift	3									
Transmission Charge Reduction Fund	3									
Capacity Reserve Settlement Debit for Operating Deviations	3									
Operating Reserve Settlement Debit for Operating Deviations	3									
4. Intertie Flow Hourly Deviation Uplift	3									Cr an
5. Ancillary Services	3	3								
Reliability Must-Run	3	3								
Black Start Capability		2								
Regulation	3	3								
Reactive Support Service and Voltage Control Service	3	3								
6. Transmission Tariff Charges	2	2	2	2						
7. Transmission Rights Auction Revenues			2		2	2				De

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8. Market Participant Default Charge		2								If ε be loc
9. Outage Cancellation/Deferral Uplift	2	2								To de
10. Market Suspension Additional Compensation Uplift	2	2								If ε co ad pa ba
11. IMO Administration Charge	2	2								Th IM all sel
12. IMO Transaction Fees						3				
13. IMO Registration Fee									3	
14. IMO Penalties						3				Pe an as:
15. Competition Transition Charge	2	3								De
16. Rural Rate Protection		3								De
17. Market Power Mitigation		3								De
18. Basic Use Service Charge			2	2						De
19. Pooled Connection Service Charge			2	2						De
20. Pooled Transformation Service Charge			2	2						De
21. Wholesale Meter Pool Charges					2					De

SUMMARY OF GROUP DISCUSSION:

The group felt that there was a lot of value in providing as much specificity in the code as possible at this time in spite of the significant uncertainty that currently exists. The uncertainty exists in at least two critical areas. The first is the uncertainty concerning what should be included in the definition of commodity charges as distinct from non-commodity charges. Referring to Table 1, the only variables that are unequivocally commodity charges are items 1 and 2, the hourly energy settlement amounts and congestion charges if they are ever implemented. The services billed through hourly uplift and ancillary service charges are necessary to support the market and maintain system stability, but the IMO is a monopoly purchaser of these services from generators and a monopoly seller of these services to wholesale market participants. Consequently, they are no different than monopoly transmission services. In other words, they are not competitive services and, therefore, might logically be excluded from the commodity portion of the electricity bill.

The second major uncertainty concerns whether some charges will be billed monthly rather than hourly. In terms of the commodity portion of the bill, the only variable that might be billed monthly is for ancillary services. Ancillary services clearly should not be included in the commodity portion of the bill; then all remaining commodity charges would be hourly which would significantly simplify the settlement calculation and eliminate some potential settlement error. A conservative recommendation would be to build in the capability to handle monthly charges as part of commodity settlement up front even if the possibility of this occurring is relatively small.

The group discussed how to handle charges from the IMO that vary monthly if, indeed, such charges exist. The primary problem is that for any given customer, the consumption period covered by a meter cycle will rarely if ever correspond to the same period of time for which the IMO monthly charges were determined. Thus, if an LDC multiplies the most recent IMO monthly charges times usage for all customers across a full meter reading cycle, the total collections based on this calculation will differ from the IMO charges because the usage amounts differ. The group concluded that there is no feasible, accurate method for ensuring that the totals are the same and that the only practical solution is for LDCs to use the most recent monthly charge available from the IMO at the time of billing when calculating individual bills.

RECOMMENDATIONS:

1. The precise elements of service billed through the IMO that constitute commodity energy costs will be determined by the OEB at a later date. At a minimum, these costs will be billed as a single cost variable for which the value will vary hourly. It is possible that there will be more than one hourly cost stream, e.g., the hourly spot price and hourly uplift, and one or more cost variables that are billed on a kWh basis once a month. LDCs must be capable of incorporating whatever cost variables are ultimately determined by the OEB to comprise commodity electricity costs into the bill calculation for individual customers.
2. If commodity costs include costs that vary monthly rather than hourly, the previous monthly value available at the time of customer billing will be used to determine settlement costs associated with a customer. The fact that the period of consumption covered by a specific meter read cycle will differ from the period of time for which monthly costs were incurred and billed by the IMO will produce a discrepancy between the amount billed to a distributor and the amount collected from end-use customers and retailers. At various times, this discrepancy may be positive or negative. To the extent that it can be quantified, any discrepancy should be accumulated in a deferral account and collected from or credited to customers according to the rules and procedures described elsewhere.

IMPLEMENTATION ISSUES:

Determining specifically what costs must be included in the commodity portion of the bill.

VOTER SUMMARY:

Unanimous.

ISSUE STATEMENT: (Final)

Global Issue Outline VI: How should non-commodity charges from the IMO be incorporated into settlement calculations?

OPTIONS:

Whatever decisions are ultimately made by the OEB regarding what should constitute the commodity, as seen in Table 1 above, there are numerous other charges that will be billed through the IMO that must be passed through to end-use customers and retailers. The degree of uncertainty concerning what specific charges will be billed explicitly by the IMO, and the characteristics of these charges is much greater for non-commodity charges than for commodity charges. The options for recommendations in this area are the same as for the commodity, namely:

1. Leave this section of the code essentially blank at this time, indicating that it will be completed when the IMO has more certainty about how costs will be charged and the OEB has provided further guidance on how these charges will be translated into billing determinants.
2. Attempt to narrow the uncertainty as much as possible by eliminating clearly unlikely or untenable options.

BACKGROUND INFORMATION:

See Table 1 above for the potential charges and the characteristics of those charges.

The RTP did not make a formal recommendation in this area. In Section 3 of the RTP report (page 3-9), the RTP acknowledged the OEB's obligation to establish rates and offered the simple guidance that the "OEB seek to allocate costs as much as possible based on the underlying factors that drive costs and to avoid distorting price signals by rolling all costs into a single price per kWh."

SUMMARY OF GROUP DISCUSSION:

The Rate Handbook currently provides no guidance concerning how IMO charges should be incorporated in rates.

LDCs are responsible for calculating bills for end-use customers and retailers that, in aggregate, include all charges billed to the LDC by the IMO.

The OEB will ultimately approve the nature of all IMO charges and define how these costs must be aggregated into selected cost categories for settlement purposes. It is possible that selected non-commodity IMO charges will be billed to LDCs according to any of the following determinants:

- Aggregate energy use in a billing month.
- Coincident LDC peak demand in a billing month.
- Non-coincident LDC peak demand in a billing month.

- Fixed charge per billing period.
- A transaction charge.
- A credit (to cover the market power mitigation credit).
- A one-time fee.

The OEB must also decide how these various charges will be billed through to end-use customers and retailers. Billing determinants for end-use customers and retailers would logically vary with metering type. For example, charges billed to LDCs by the IMO based on peak demand would logically be billed to demand-metered and interval-metered customers based on peak demand. However, for kWh-metered customers, costs that are billed to LDCs based on demand might be translated to usage-based charges.

It is recognised that virtually any cost allocation process will be imperfect and lead to over or under-collection of non-commodity wholesale market costs from end-use customers or retailers for any given period of time. In light of this fact, the group feels strongly that it would simplify the settlement process if, rather than trying to pass costs that vary monthly through on a regular basis, a forecast of total costs for IMO charges for the year should be developed and customers should be billed according to the same price each month. These charges could still be broken down and billed based on kWh, demand or fixed amounts but they would not vary monthly even though charges from the IMO to LDCs would vary monthly. LDCs would accrue revenue collected from customers into an account for the year and compare these revenues with costs incurred for the same category of IMO charges. Any differences, positive or negative, would be reflected in the price forecast for the subsequent year.

RECOMMENDATIONS:

1. The precise elements of service billed through the IMO that constitute non-commodity costs will be determined by the OEB at a later date. LDCs are responsible for determining bills for end-use customers and retailers that, in aggregate, include all charges billed to the LDC by the IMO.
2. Working with the IMO, the OEB should develop a forecast at the beginning of each year that would cover the expected cost for all IMO non-hourly, non-commodity charges for the year. These charges might be billed partially based on energy use, demand or on a fixed amount per customer. LDCs would be obligated to bill all customers according to these rates and to track revenue collected through these charges. LDCs would also be obligated to pay the IMO for all charges billed each month by the IMO. At the end of each year, the revenue collected will be compared to the actual charges paid to the IMO by the LDC for the same period. Any differences will be reflected in the rates charged by an LDC in the subsequent year.

IMPLEMENTATION ISSUES:

Determining specifically what costs must be included in the non-commodity portion of the bill.

Developing the rate forecast.

VOTER SUMMARY:

Unanimous.

ISSUE STATEMENT:

Global Outline Issue VII.C: Access Rights to Meter Data

This issue concerns retailer and customer access to current meter data, not historical usage records. The latter was covered by subgroup 1.

- What type of meter data must be made available to retailers and end-use customers?
- What timing must be associated with data provision?
- What means must be used to communicate meter data?

OPTIONS:

Data provision to retailers:

1. Both raw data and VEE data must be made available.
2. Only VEE data must be made available.
3. Data must be made available prior to issuing normal settlement invoices.
4. Data must only be provided along with normal settlement invoices.
5. Retailers must only be provided with access to the meter, not to data provided by an LDC.
6. Retailers must be provided not only with access to the meter, but must also be provided with access to data through the EBT system that will be designed for electronic communication for various information between LDCs and retailers.
7. Retailers should not have access to the meter but should only be provided with access to meter data through the EBT system.

Data provision to customers:

1. Both raw data and VEE data must be made available to customers.
2. Only VEE data must be made available to customers.
3. Only raw data must be made available to customers.
4. Usage data must only be provided to customers on their bills, not separately.
5. Access to usage data separate from a customer's bill must be provided.
6. Customers must only be provided with access to the meter, not with data access through an EBT system.
7. Customers do not have to be provided with access to the meter, but must be provided with access through the EBT system.

BACKGROUND INFORMATION:

The RTP spent significant time discussing the above issues and options but primarily in the context of a market with competitive metering services. In light of the working assumption that metering will not be competitive at the time of market opening, some of the RTP recommendations may not apply.

The RTP recommended that competitive MDMAs post all data gathered, whether from remotely or non-remotely read interval meters or from kWh meters, on a web site for access by LDCs, customers or retailers via the internet. For LDCs providing default MDMA services, the RTP recommended that they be required to post remotely read interval data on a web site, but that all non-remotely read usage data could be communicated via a customer's bill. The RTP recognised the difficulty of putting hourly data for non-remotely read interval meters on a customer's bill but did not resolve this issue. The RTP recommended that, in general, data should be communicated using a common format.

With respect to customer access to information, the RTP provided the following recommendation (RTP recommendation 5-22):

Customers with remotely read, hourly interval meters should have electronic access to the bill-ready hourly usage information on an MDMA web site for their accounts. Usage data should be maintained on an MDMA server for at least three months.

Non-hourly usage data is adequately communicated on written customer bills.

Customers should have the right to access meter information or interrogate the meter free of charge in accordance with any applicable technical specifications and codes. However, the terms for the provision of pulse output devices and/or interrogation devices and interpretation software should be negotiated freely between market participants.

SUMMARY OF GROUP DISCUSSION:

Retailer access:

Retailers require timely access to usage data in order to bill their end-use customers. A retailer may or may not base its price offer to an end-use customer on the wholesale spot price. A fixed price offer to a customer does not require access to spot-price data in order to issue a bill to a customer. Retailers billing customers based on such an offer will want access to usage information as soon as it's available, which for kWh-metered customers, is significantly sooner than it's possible for an LDC to issue a bill to a retailer based on the net system load weighted average spot price. For example, kWh usage data that has been through a VEE process could probably be made available to retailers within 24 to 48 hours of a meter reading. Raw data could probably be made available even faster. On the other hand, settlement bills from LDCs to retailers will not be able to be issued until perhaps as long as two weeks after a meter reading because of the time lag of ten business days involved in obtaining load shape data and price data from the IMO. Consequently, it would seem unreasonable to require retailers to wait for usage data to be delivered along with settlement invoices.

The precise timing of data available from various types of meters is discussed under Issue VII.E. Timing is also dependent upon the precise VEE standards that will be imposed and the amount of time it will take to adhere to those standards once a meter has been read.

Subgroup 4 has recommended, and the Task Force has approved, that meter data be communicated from LDCs to retailers via the EBT system that will be implemented at market

opening.

Customer access:

With the possible exception of very large customers, most end-use customers will be content to have access to usage information through their regular bills. Customers with interval data may or may not want access to hourly information. Even those that do may not require access in the same timeframe, as would retailers. A few may want direct access to the meter in order to implement load management measures.

RECOMMENDATIONS:

Retailer access:

1. Retailers must be provided with timely access to interval meter usage information independent of the information provided to retailers as part of the normal settlement invoicing process. The minimum data that must be made available is as follows:
 1. LDC customer account number.
 2. LDC meter number.
 3. Service address.
 4. Date of most recent meter read.
 5. Date of previous meter read.
 6. kWhs recorded at time of most recent meter read.
 7. kWhs recorded at time of previous meter read.
 8. Multiplied kW for the billing period (if demand metered).
 9. Multiplied kVa for the billing period (if available).
 10. Usage for each hour during the billing period for interval-metered customers.
 11. Indicator of read type (e.g., utility read, customer read or utility estimate).
2. All VEE'd meter usage data must be provided to retailers electronically via the EBT system that will be developed prior to market opening.
3. Raw data must be kept on record by LDCs and be made available to customers upon their request.
4. For all non-remotely read meters, whether kWh, demand or interval meters, the data (including estimate data) must be made available once every billing cycle.
5. Remotely read interval data must be made available in accordance with the meter reading cycle defined elsewhere.
6. A customer may assign his or her rights to access the meter, as defined below, to a retailer.

Customer access:

1. Customers with remotely read, hourly interval meters should at a minimum, have electronic access to data according to the same rules as for retailers, as described in recommendations 1 through 3 above.
2. Manually read interval data, which will be retrieved according to an LDC's normal meter reading cycle, will also be made available to customers electronically using the same rules and procedures as for retailers.
3. Non-hourly usage data is adequately communicated to customers in printed form on customer's bills. LDCs need not accommodate electronic access to or provide such data to customers independent of their bills.
4. Customers have the right to access meter information and interrogate their meter in accordance with any applicable technical specifications and codes.

Where the customer desires regular access to metering information this access shall be provided under the following conditions:

- The LDC, must have priority access to interrogate the meter, access windows for the customer to be negotiated with the LDC.
- The software, hardware or any other costs required by the customer or any third party to access this data shall be borne by the customer.
- If the customer's access to the meter interferes with the LDC or MDMA's ability to access the meter or corrupts the data, their rights to directly interrogate the meter may be suspended. This right will be suspended until this problem is resolved with the responsible LDC.
- The customer will pay for the cost of the service calls required to fix meter problems caused by the customer.

Where the customer requires access to the meter data on a continuous basis a secondary system, compatible with the LDC's system shall be installed under the supervision of the LDC, with all pertinent costs borne by the customer.

Notes:

1. The customer is responsible for the actions of a retailer or any other party they've given the rights to access their meter.
2. LDC = LDC's MDMA group or a third-party MDMA the LDC has contracted this responsibility with.

Where a meter is changed out by the LDC, it must be posted as a meter read.

IMPLEMENTATION ISSUES:

Data formats and EBT process.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT:

Global Issue Outline VII.D: Data Storage and Maintenance

- How long should the window be for accessing usage data posted on the EBT system?
- How many billing periods of usage data should be retained on-line at the same time?

OPTIONS:

1. Have a very narrow (e.g., 24-hour) opportunity to access usage data before it is purged.
2. Have a longer (e.g., 30-day) opportunity to access usage data.
3. Retain only the most recent billing cycle data on the EBT server.
4. Retain several billing cycles' worth of information on the EBT server.

BACKGROUND INFORMATION:

There are several different issues related to record retention. For example, subgroup 1 dealt with provision of historical customer information, indicating that two year's worth of data must be made available upon request. Subgroup 1, Issue II.C.6, addresses retention of a variety of information around customer registration and transfer procedures.

In addition, there are potentially a variety of federal, provincial and municipal laws governing record retention, including rules established by Measurement Canada.

The issue addressed here concerns retention of meter data on-line for use by retailers for billing purposes. That is, it concerns only the data identified in the Issue VII.C discussion. The RTP recommended that three months' worth of usage data be retained on-line (recommendation 5-23, in part).

SUMMARY OF GROUP DISCUSSION:

Conceptually, the minimum amount of time that data should be retained on-line is the time it takes for all retailers and customers who obtain usage data via the EBT system to access the system and download the information. At the low end, this might only be, say, one business day after posting. However, in light of the reasonably low cost of data storage and the importance of providing flexibility to retailers to access data according to a variety of reasonable business practice time lines that may develop, retaining data for such a short period of time would seem unreasonable. A more reasonable window might be to allow retailers (and end-use customers who may access data in this manner) at least 30 calendar days to obtain the data or to retain the data for a single billing period.

A second issue concerns how many billing-period records should be retained on-line at a particular point in time. As mentioned in the background section, the RTP recommended that three-months' worth of data be made available. It's unclear from the RTP report whether the intent was to retain three month's worth of data or three billing period's worth of data.

There would appear to be little reason to retain more than the current billing period's worth of data on-line. If a retailer or customer wishes to have easy access to more than a single period's

worth of data, they can access the data once it is posted and store it themselves. If a large number of customers are served by retailers, storing multiple billing periods on-line in a centralised location will require a lot of storage, especially for interval data.

RECOMMENDATIONS:

For all meters, usage data (as defined in recommendation 1, Issue VII.C) for a single billing period must be available on the EBT system and remain accessible to all relevant parties until replaced by data for the next billing period.

IMPLEMENTATION ISSUES:

EBT process.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT:

Global Issue Outline VII.E: Meter Reading Schedules

- How frequently must meters be read?
- How soon after meters are read must data be made available to retailers?

OPTIONS:

1. Allow each LDC to determine the meter reading frequencies for all meters.
2. Allow each LDC to determine the meter reading frequency for all non-remotely read meters but establish a common read schedule for remotely read meters.

BACKGROUND INFORMATION:

The RTP spent significant time discussing meter-reading schedules in the context of a competitive meter service market. In light of the working assumption that metering will not be competitive at the time of market opening, not all of the RTP's recommendations apply, but many are still relevant. The remainder of this background section is reproduced verbatim from the RTP final report.

The subpanel discussed and agreed on the timing of meter reading and the schedule and standards for the provision of meter-reading data. The subpanel's conclusions differ for remotely read interval meters for MDMA's reading meters that are not remotely read and for LDCs reading meters that are not remotely read. In addressing the issue, the subpanel balanced LDCs' cash-flow requirements, the need for timely provision of validated hourly data in order to expedite the process of developing a net system load profile for settlement purposes, the burdens and expense placed on competitive MDMA's by the meter reading requirements and the burdens and expense placed on LDCs that must offer meter reading on a default basis.

The subpanel agreed on the following meter-reading requirements for remotely read, hourly interval meters, irrespective of whether such meters are read by an LDC or a competitive MDMA:

- Remotely read, hourly interval meters should be read weekly. The weekly interval would be midnight on Sunday to midnight the following Sunday.
- By noon on the first business day after Sunday (for most weeks this will be Monday) 80 percent of the hourly interval data for the prior week, for which an MDMA is responsible, must be posted on the MDMA's Web site. Irrespective of what day is the first business day after Sunday, by noon on Thursday, 100 percent of the hourly interval data for the prior week, for which an MDMA is responsible, must have undergone VEE and be posted on the MDMA's Web site. (If the data is not available, an estimate must be posted. VEE standards will determine the maximum amount of estimated data that may be used.)

The weekly schedule was chosen because it provides LDCs with remotely read, hourly interval data within the time frame currently under discussion for the development of net system load profiles. Monthly provision of such data was discussed but rejected because it would add significant lag time to the settlement process. Moreover, weekly provision of the information was found to be reasonable. First, the subpanel learned that frequent meter interrogation does not add significant costs to MDMA activities, except for meters that are read via satellite. Some

incremental costs may result from requiring MDMA to subject data to the VEE process on a weekly basis. However, since the volume of weekly data is proportionately less than the volume of monthly data, the incremental costs of weekly versus monthly provision of data should not be significant. Noon was used as the deadline for data submission to allow an MDMA half a day to work with the bulk of the data and an LDC the second half of the day for settlement and billing.

The subpanel recognised that the result of placing the weekly meter reading, editing and posting obligations on LDCs, as well as competitive MDMA, is that LDCs that offer default MDMA services to remotely read interval meters will have to acquire a server and make it accessible to customers and retailers. The subpanel nonetheless recommends that these requirements be applicable to LDCs for two reasons. First, in this manner, there is a workable consistent mechanism across the province by which customers and retailers will have ready access to detailed hourly interval data supporting billing. Second, the schedule for reading hourly interval meters, subjecting it to VEE and posting it, is driven in large part by the need to develop a net system load profile in a timely manner. The timing of the development of a net system load profile is equally dependent on the timely provision of hourly data from meters read by LDCs as it is on the timely provision of hourly data from meters read by retailers. The subpanel noted that LDCs will have the option of contracting out default MDMA services for remotely read interval meters if it is not cost effective for them to set up a server themselves.

The weekly schedule would be onerous for interval meters that are not remotely read since it would require weekly visits to the meter site. The results of a survey undertaken by Acres International indicates that there are some but not many hourly interval meters that are not remotely read. The subpanel believes, moreover, that the volume of energy represented by these meters is not substantial and could be excluded from the net system load profile development process. Accordingly, the subpanel determined that hourly interval meters that are not remotely read should be subject to the rules on meter-reading schedule and the provision of data that apply to non-interval meters.

The subpanel agreed on the following meter-reading requirements for meters that are not remotely read:

- Meters that are not remotely read must be read at least as often as such meters are read by LDCs. MDMA must inform LDCs of the meter-reading date and may not change such date without the consent of LDCs more often than once a year.
- By noon on the first business day after the scheduled meter-reading date, 80 percent of the meter-usage data for which an MDMA is responsible must have undergone VEE and be posted on the MDMA's Web site. By noon on the fourth business day after the meter-reading day, 100 percent of the meter-usage data for which an MDMA is responsible must have undergone VEE and be posted on the MDMA's Web site.
- LDCs providing MDMA services on a default basis for non-remotely read meters may finalise usage data and undertake billing in accordance with their current practices.

The Retail Technical Team determined that non-remotely read meters must be read at least as often as such meters are read by LDCs. Moreover, MDMA must inform LDCs of the meter-reading date and may not change such date without the consent of LDCs more often than once a year. An alternative to requiring MDMA to read meters on an LDC's scheduled meter-read date (unless an LDC and an MDMA can agree on a different date) was discussed but found to be unacceptable by the Retail Technical Team because it would make it nearly impossible for MDMA to compete in the non-remotely read meters market. This is because the alternative would make it very difficult for MDMA to optimise the efficiency of meter reading since they would not have the flexibility to establish their own meter-reading routes. Allowing MDMA to

determine the meter-reading date means the LDCs must adjust their billing system to accommodate different MDMA meter-reading dates. To minimise burdens on LDCs, MDMA's are precluded from changing the meter-reading date more often than once a year without an LDC's consent.

The subpanel agreed that the bulk of usage data (80 percent) should be available on an MDMA's Web site by noon on the first business day after the meter-reading date. The remainder of the data should be posted by noon on the fourth business day. If no reading has been obtained by then, an estimate should be provided in accordance with VEE rules. These requirements are generally consistent with existing practice for utilities that contract out meter-reading activities.

The subpanel determined that LDCs offering MDMA services for non-remotely read meters on a default basis could be exempted from additional requirements on the timing of meter reading and the provision of data. As is described in subsequent sections 5.18 and 5.19, for these meters the bill will serve as the vehicle to communicate the usage data that supports billing; usage data from such meters will not be posted on a server. Accordingly, market participants have less of a stake in the timing of meter reading.

Moreover, the subpanel found that LDCs have different practices as to the timing of meter reading, VEE and bill production to account for differences in service territories, e.g., rural versus urban and meter-reading/billing approaches. The subpanel did not believe it is indispensable to eliminate these differences, for non-remotely read meters, in order to introduce competition in MDMA services. Moreover, eliminating the differences would likely be disruptive to some LDCs. The subpanel recognised that the additional flexibility given to LDCs could give them a competitive advantage in the MDMA market for non-remotely read meters. However, the subpanel judged that, on balance, it is more important to allow LDCs to offer these services on a default basis in a manner that is not overly disruptive.

Recommendation 5-19:

Remotely read, hourly interval meters should be read weekly. The weekly interval would be midnight on Sunday to midnight the following Sunday. By noon on the first business day after Sunday (for most weeks this will be Monday) 80 percent of the hourly interval data for the prior week, for which an MDMA is responsible, must have undergone VEE and be posted on the MDMA's Web site. Irrespective of what day is the first business day after Sunday, by noon on Thursday, 100 percent of the hourly interval data for the prior week, for which an MDMA is responsible must have undergone VEE and be posted on the MDMA's Web site.

Meters that are not remotely read must be read at least as often as such meters are read by LDCs. MDMA's must inform LDCs of the meter-reading date and may not change such date without the consent of LDCs more often than once a year. By noon on the first business day after the scheduled meter-reading day, 80 percent of the meter-usage data for which an MDMA is responsible, must have undergone VEE and be posted on the MDMA's Web site. By noon on the fourth business day after the scheduled meter-reading day, 100 percent of the meter-usage data for which an MDMA is responsible must have undergone VEE and be posted on the MDMA's Web site.

LDCs providing MDMA services on a default basis for non-remotely read meters may finalise usage data and undertake billing in accordance with their current practices.

SUMMARY OF GROUP DISCUSSION:

While many would agree that a common set of meter reading practices across all meter types would significantly simplify and streamline settlement, imposing such standards could

significantly increase costs for many LDCs. Even if common standards were imposed, the practical realities of meter reading in Ontario would lead to a significant amount of exception processing and far from universal availability of usage information on a monthly or bimonthly basis.

An exception to the above view pertains to remotely read interval metering. With remote access, the cost of changing meter reading frequency from current practice and adhering to a common schedule is minimal. Furthermore, the importance of obtaining data in sufficient time to include in determination of the NSLS is great. Consequently, having a common standard in this area is important to the overall settlement timeline.

Regarding the issue of the timing of data availability following meter reads, it is important that retailers have access to data as quickly as possible. However, stringent timelines may be difficult for some LDCs to meet given limited staff redundancy. For small LDCs, a single person being sick could delay issuance of bills for several days. Consequently, it may be difficult for small LDCs to always post meter usage data on time.

RECOMMENDATIONS:

1. All remotely read, hourly interval meters must be read at least weekly. The weekly interval must be midnight on Sunday to midnight the following Sunday. By noon on the second business day after Sunday, all validated hourly interval data for the prior week must be delivered to the mandatory EBT system. Irrespective of what day is the first business day after Sunday, by noon on Thursday, 100 percent of the hourly interval data for the prior week must have undergone the complete VEE process and be delivered to the mandatory EBT system.
2. Non-remotely read interval meters and non-interval meters may be read according to an LDC's normal meter-reading cycle. For all customers served by retailers, by noon on the second business day after the scheduled meter reading day, all validated meter-usage data must be delivered to the mandatory EBT system. By noon on the fourth business day after the scheduled meter-reading day, 100 percent of the meter-usage data must have undergone the complete VEE process and be delivered to the mandatory EBT system.
3. For customers that are served by a distributor, interval-metered data, whether remotely or manually read, must be made available in the same fashion as described in recommendations 1 and 2 above. As described in recommendation 10, Issue VII.C, non-interval usage data will be communicated to end-use customers through their bills and, therefore, is not subject to the same timeline as is required for delivery to retailers.

IMPLEMENTATION ISSUES:

VEE procedures will be addressed in the DSC.

VOTER SUMMARY:

Eighteen in favour; one against.

DISSENTING OPINIONS:

None specific.

ISSUE STATEMENT:

Global Issue Outline VII.I: Treatment of Meter Errors

- How should collections and payments associated with meter errors be handled in light of the three-way relationship between LDCs, retailers and customers?

OPTIONS:

See background section.

BACKGROUND INFORMATION:

The RTP spent significant time discussing how to handle meter errors when metering is competitive. In light of the working assumption that metering will not be competitive at the time of market opening, not all of the RTP's recommendations apply, but many are still relevant. The remainder of this background section is reproduced verbatim from the RTP final report.

"The subpanel discussed various alternatives for liability of MSPs and MDMA. It discussed in particular, the liability of an MSP or MDMA for billing errors resulting from metering errors. The subpanel also discussed general business liability, including liability for damage to property or persons.

The subpanel spent the bulk of its time discussing liability for billing errors resulting from a metering error caused by an MSP or an MDMA. It determined the following with regard to such errors:

- Whenever an LDC has to pay customers or retailers or collects from customers or retailers due to a meter-related error, the payment or collection should be spread to all other customers through an adjustment to Unaccounted for Energy (UFE). This is because during the time the error exists, it will result in more or less UFE than there otherwise would have been; thus, other customers will pay for or benefit from the error through UFE charges until the error is found and corrected. (Separate from this mechanism for adjustments, the OEB could, through performance-based rate making, set up a system of rewards and penalties related to performance by an LDC on metering accuracy. This system should only reward or penalise an LDC for metering accuracy related to cases where an LDC is responsible for MSP and/or MDMA services.)
- Irrespective of whether an LDC or a retailer is responsible as an MSP or an MDMA for meter errors, the entity that owes the other money as a result of the error should be required to make an adjustment.¹ For example, irrespective of who is responsible for the meter error, if as a result a customer has been undercharged, the customer owes money to the LDC and the retailer. Thus, the LDC and retailer should collect from the customer. Similarly, if the customer has overpaid, the LDC and the retailer should reimburse the customer.
 - Adjustments vis-à-vis an LDC for metering errors should include adjustments for distribution, transmission, other charges and energy at the pool price irrespective of any agreement between a retailer and a customer.

¹ Proper calculation of adjustments would have to take into account any intervening rebates by Genco pursuant to the price cap describe in the *Third Interim Report* of the MDC, 1-6-1-13.

- If an LDC bills a customer for all services (transmission, distribution, other charges and energy) directly, an LDC should make an adjustment on the customer’s bill for all these services. If an LDC also bills for a retailer, an LDC should allow a retailer to make necessary adjustments to the retailer portion of the bill; however, an LDC should merely include the amounts stated by a retailer in the bill. An LDC should have no responsibility for the accuracy of these amounts (other than to accurately include in the bill the figure submitted to it by a retailer).
- If an LDC bills a customer for transmission, distribution and other charges and a retailer for energy, an LDC should adjust and collect from or refund a customer for the transmission, distribution and other charges portion of the bill; and it should adjust and collect from or refund a retailer for the energy portion of the bill (this adjustment will be at the pool price).
- If an LDC bills a retailer for all services (and a retailer in turn bills a customer), an LDC should adjust and collect from or refund a retailer for all services: distribution, transmission, other charges and energy at the pool price.
- Adjustments between a customer and a retailer must be dealt with between those two entities in accordance with their contract. An LDC should have no responsibility for such adjustments. (The OEB may or may not play a role in this area depending on the extent to which the OEB has more general oversight over the relationship between customers and retailers.)
- It is important to clarify whether or not an LDC that tries but fails to collect from a retailer for a metering error has recourse to the customer for an adjustment. This issue should be treated consistently with whether an LDC that tries but fails to collect from a retailer for other charges has recourse to a customer for those charges.
- Retailers, LDCs and customers must be notified of any adjustments due to meter errors made to one another. It is particularly important that customers be notified of any adjustments made by an LDC to a retailer due to a metering error, so that customers can seek or expect to make any necessary corresponding adjustments to or from their retailer.
- Irrespective of whether or not entities are entitled to or can collect against each other for billing errors arising from meter errors, entities responsible for meter errors should not be required from a regulatory standpoint to serve as a secondary recourse.² Instead, retailers and LDCs should be subject to reasonable regulatory penalties for failures to meet metering-related performance criteria. (The relationship between a retailer and an MSP it contracts with would not be regulated and could include any form of sharing of liability or indemnities that are mutually agreed upon between the two organisations.)
 - Regulatory penalties paid by an LDC for failure to meet performance criteria for MSP and MDMA activities would be a transfer from LDC shareholders (i.e., such penalties should not be recovered through rates) to UFE.

² An entity that underbilled another due to a metering error may not always be able to collect the amount owed it. First, in some cases, the amount owed does not justify the cost of collection. Second, in some cases, the underbilled entity might successfully defeat a collection action, for example, by proving negligence on the part of the entity seeking to collect (see *The Hydro Electric Commission of the Town of Kenora and The Corporation of the Town of Kenora v. Vacationland Dairy Co-operative Ltd.* (1994) 1 S.C.R. 80). Moreover, the fact that an entity is not required from a regulatory standpoint to serve as a secondary recourse would not necessarily insulate it from negligence or other common law actions arising from its activities.

- Regulatory penalties paid by a retailer for failure to meet performance criteria for MSP and MDMA activities would also be credited to UFE.
- Regulatory penalties should be reasonable, i.e., they should be designed to give MSPs and MDMA proper incentives to undertake their responsibilities accurately and reliably.

While a majority of subpanel members agreed with this last recommendation, there was a strong contingent of subpanel members that believe instead that an MSP or an MDMA that is responsible for a meter error should be required to pay for the loss caused by that error to an LDC, retailer or customer that is otherwise unable to collect the appropriate adjustment from the corresponding entity. If this alternative were chosen, an MSP or an MDMA that paid on behalf of the entity that failed to pay would inherit the right to attempt to collect from that entity.

The majority determined that regulatory penalties were preferable because:

- The liability of an MSP or an MDMA should not be determined by the level of effort of another entity to collect from a third entity that owes it money.
- The regulatory penalties approach is more predictable, minimises risk for MSPs and MDMA and hence facilitates market entry.
- There was particular concern that LDCs, which must offer MSP and MDMA services on a default basis, should not become collection agents for retailers. It was noted that notwithstanding the best efforts of an MSP or an MDMA, it is impossible to completely eliminate meter errors.
- This approach is consistent with R4-25 in the Second Interim Report (which recommends that “the rules establish that a competitive meter supplier bear liability for safety violations, installation problems, billing errors, damage to the distribution system and damage to customer property arising from faulty or improper installations”) because an MSP or an MDMA would be required to pay regulatory penalties due to billing errors. Moreover, payment of such penalties would not depend on whether another entity is able to collect money owed it, but rather such penalties would be based solely on the performance of an MSP and an MDMA.

The members that believe MSPs and MDMA should be liable for billing errors, if an entity is unable to collect, argue that

- This approach is more consistent with R4-25 in the Second Interim Report since an MSP or an MDMA may be liable for the billing error.
- Since the risks to an MSP and an MDMA are greater under this approach, the approach gives an MSP and an MDMA greater incentives to ensure accurate metering.
- If there is a significant concern related to the liability of LDCs that must provide default metering services, LDCs only could be shielded from such liability and subject to penalties.

Although the system of penalties was preferred by a majority of subpanel members, the subpanel was informed that the OEB may not have authority to apply regulatory penalties. Even if this is the case, a system of meter error-related penalties could be made a part of a regulated LDC-retailer contract, if such a contract is developed.

The subpanel briefly discussed general business liability of MSPs and MDMAs for damage to property or persons. The subpanel concluded that such liability should be the same for MSPs and MDMAs as it is for any other business entity. There is no need to devise special rules, provided no rule exempts an MSP or an MDMA from liability.

Recommendation 5-15:

Whenever an LDC has to pay customers or retailers or collects from customers or retailers due to a meter-related error, the payment or collection should be spread to all other customers through an adjustment to UFE.

Irrespective of whether an LDC or a retailer is responsible as an MSP or an MDMA for meter errors, the entity that owes the other money as a result of the error should be required to make an adjustment.

Adjustments vis-à-vis an LDC for metering errors will include adjustments for distribution, transmission, any other charges and energy at the pool price irrespective of any agreement between a retailer and a customer.

Retailers, LDCs and customers must be notified of any adjustments due to meter errors made to one another. It is particularly important that customers be notified of any adjustments made by an LDC to a retailer due to a metering error so that customers can seek or expect to make any necessary corresponding adjustments to or from their retailer.

Irrespective of whether or not entities are entitled to or can collect against each other for billing errors arising from meter errors, entities responsible for meter errors should not be required from a regulatory standpoint to serve as a secondary recourse. Instead, retailers and LDCs should be subject to reasonable regulatory penalties for failures to meet metering-related performance criteria.

If it is not possible to levy regulatory penalties on an MSP and an MDMA, a system of meter error-related penalties could be made part of a regulated LDC-retailer contract, provided such contract is developed.

General business liability of an MSP or an MDMA for damage to property or persons should be the same as for any other business entity.”

SUMMARY OF GROUP DISCUSSION:

The RTP’s recommendation that meter error adjustments should be spread to all customers through an adjustment to UFE appears to assume that UFE adjustments are made frequently. In light of the recommendation that DLF and UFE factors will be adjusted infrequently in order to provide LDCs with the proper incentive to manage these factors, the RTP recommendation does not appear to make sense.

Depending upon the length of time that a meter has been inaccurately recording usage, there are numerous scenarios that vary with respect to the number of market participants involved (e.g., multiple retailers and multiple customers at the same location) and the billing options selected. Consequently, it may make sense to base the rules in the settlement code around a set of principles and “best efforts” clauses rather than to try and prescribe a precise set of rules covering every possible contingency. Potential guiding principles might include a statement that no market participant should enjoy a windfall gain or suffer a loss as a result of a meter error as long as the effort to properly attribute gains and losses to the appropriate party is reasonable. This principle would mean, for example, that a retailer must pass through costs or payments to

the end-use customer associated with a meter error if the customer had previously underpaid or overpaid, respectively, as a result of the error. It would also mean that, if the retailer had changed during the period over which errors had occurred, the current retailer should neither gain nor lose at the expense of the previous retailer, as long as the previous retailer was still in business and could easily be tracked down. If the previous retailer was out of business, any share of incremental costs or payments associated with that previous retailer should either be borne by the LDC or the customer, not the current retailer.

RECOMMENDATIONS:

1. Where a billing error, from any cause, has resulted in an over billing and where Industry Canada has not become involved in a dispute, the customer will be credited with the amount erroneously paid. For practical reasons, such as record retention, the amount erroneously paid for a period up to six years normally is considered appropriate.
2. Where a billing error, from any cause, has resulted in an under billing and where Industry Canada has not become involved in a dispute, the customer will be charged with the amount erroneously not billed. In the case of an individual residential customer not responsible for the error, the usual practice is to use a period not exceeding two years. For other applications, including instances of wilful damage, the amount erroneously not billed for a period of up to six years is considered appropriate.
3. Whichever entity is billing the customer is responsible for advising the customer of the meter error and its magnitude and subsequently settling actual payment differences with the customer as described above.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Eighteen in favour, one against.

DISSENTING OPINIONS:

One member suggested this issue should also address the payment responsibility of retailers and customers when a meter error is discovered under the retailer consolidated billing option. If the error is material, there should be a process for the retailer to pay the LDC based on payment from the customer and the customer should be able to pay for the outstanding amount

ISSUE STATEMENT: (Final)

Global Issue Outline VIII.A.3: Retail Settlement Systems Timeline

- How long should it take following a customer's meter reading date to calculate and issue invoices to competitive retailers? (Note: Payment of invoices by retailers is being covered by subgroup 2.)
- Will shortening the time required for invoicing through the use of preliminary information increase the frequency and magnitude of invoicing errors?
- If errors occur, should future invoices be adjusted to reflect these past mistakes?
- Should the settlement timeline accommodate full reconciliation of the sum of estimated loads to the total system load?

OPTIONS:

Two key issues are the timing of preliminary and final data from the IMO that must be used for bill calculations and whether or not a reconciliation process should be used to adjust customer/retailer-specific cost allocation estimates for differences between total system load and the usage-weighted sum of initial customer-specific estimates. (For further explanation of the reconciliation process, see the discussion starting on page 3-14 of the RTP Report and RTP recommendation 3-9, which is reproduced below.) The following options were discussed:

4. Utilise final verified data from the IMO with full loss reconciliation.
5. Utilise final verified data from the IMO without loss reconciliation.
6. Utilise preliminary statement data from IMO without loss reconciliation.
7. Utilise unverified wholesale and retail interval meter data and "six-day" wholesale price data.
8. Leave the choice up to each LDC.

BACKGROUND INFORMATION:**IMO Settlement Timeline:**

Wholesale real-time market price issued by IMO to LDCs:

Provisional	5 minutes
Preliminary	2 days
Final	6 days

Daily wholesale statements issued to LDCs:

Preliminary	10 business days
Validation process	+4 business days
Final statement	20 business days (i.e., a calendar month)

Monthly invoice issued by IMO to LDCs (based on calendar month):

Issued ten business days after the last day of the calendar month.
Based on both preliminary and final statements plus any adjustments.

Payment due two business days after invoice.

Current LDC Practices:

Some LDCs issue customer bills the day after the meter reading date. Virtually all LDCs issue bills within six days of meter reading.

Relevant RTP Recommendations:

RTP Recommendation 3-9:

Adjustments for losses and UFE should not be based on contemporaneous reconciliation to total system losses. Reconciliation involves calculating the difference between the sum of all individual hourly loads, adjusted for losses and UFE and the total system load; and allocating this difference back across the individual loads. As an alternative, the RTP recommends that aggregate error be calculated on an annual or biannual basis and that periodic adjustments are made in distribution loss estimates and UFE. The RTP does not recommend billing for historical “true-ups” associated with any residual error determined through this periodic evaluation.

RTP Recommendation 3-16:

The RTP recommends that LDCs be allowed to establish their own retail settlement timelines consistent with their normal meter-reading, billing and other business practices. Payment terms for retailers should be the same as those for the end-use customers they serve.

RTP Recommendation 5-19:

VEE customer load data from remotely read interval meters will be available within ten business days.

SUMMARY OF GROUP DISCUSSION:

- This issue concerns the calculation of regular bills only. Final and off-cycle bills will be considered elsewhere.
- There was substantial debate about whether the recommendations made below should apply equally to bills offered to both retailers and end-use customers. It was recognised that, as a practical matter, any decision concerning timing for retailer bills is likely to result in the same timing for end-use customer bills and vice versa.
- Reconciliation requires that all end-use meters on a distribution system be read. Ignoring missed reads, this means that final settlement with reconciliation would require holding up settlement for an entire read cycle beyond when it could be done without reconciliation (e.g., 30 days for monthly reads, 60 days for bimonthly reads, etc.). Missed reads are problematic and can mean that final reconciliation might not be possible for more than a year. (In the UK it's done 15 months later, whether or not all meters are read.). General concern was expressed regarding the difficulty of obtaining actual meter readings for hard-to-access meters. This is a real problem in older areas of a city (where meters are often indoors) and where a large percent of the population works during the day.
- There was unanimous agreement to accept RTP recommendation 3-9 that recommends not employing reconciliation.

- With reconciliation off the table, the range in timing between options 2 through 4 is roughly 24 business days. That is, using final IMO data means invoices can not be issued for roughly 30 calendar days (20 business days) after the meter read date. Preliminary data allows LDCs to issue invoices roughly 15 calendar days (ten business days) after the read date. Option 4 would cut four days off of the preliminary data timeline but would require shortening the time period for delivery of VEE data from interval meters which could be problematic.
- There was general agreement that only VEE meter data should be used, although one group member suggested considering use of the 24 hour preliminary price data from the IMO with the difference between this data and final data being tracked. Given that VEE data for LDC interval meters will not be available until 10 business days after each daily read, as outlined in RTP 5-19, this essentially eliminates option 4 from consideration.
- Final statements allow 4 days to identify and resolve statement problems concerning either volume or price. Most group members felt that large errors will be few in number and, if they occur, it is unlikely that they will be resolved in four days. Thus, there should be few differences between preliminary and final invoices most of the time. However, it was also recognised that errors may be identified well beyond the normal billing cycle. That is, an error might be identified six months or longer after bills have been issued.
- If an error is discovered, it must be decided whether adjustments should be made to the invoices for the affected group of retailers/customers, allocated to all customers or simply ignored and, thus, absorbed by LDCs. (Note that any error associated with a specific customer, such as a meter error, would be corrected for that customer.) An important consideration is the impact of any decision on LDCs in light of PBR regulation. Errors resulting in over-collections would positively impact an LDCs bottom line while errors resulting in under-collections would have a negative impact. In considering this issue, it was noted that this is not an all-or-nothing decision. That is, a decision could be made to have LDCs absorb “small” errors (positive or negative) while requiring that adjustments for “large” errors be allocated to the affected customer population. When this issue was discussed among the entire Task Force (rather than at the subgroup level), one participant questioned why even small errors should not be properly allocated. A suggestion was made that the OEB staff informs the subgroup about any relevant parallels in the gas industry.
- Assuming that adjustments for errors are made on the bills of the affected population, rules must also be developed around final bills. For example, if an error is not discovered until months after a customer or retailer leaves the distribution system, should the customer or retailer be pursued for additional collections or rebates?
- The treatment of errors was discussed at length at the subgroup meeting on June 24. Among the issues discussed in detail were the need to retain data for audit-trail purposes, how corrections would be made, the need to rebill customers, the ability of billing systems to handle mass bill adjustments/corrections, the use of best available data at the time of billing, whether adjustments should be customer-specific, whether adjustments should be issued to past customers or current ones and alternative methods for issuing any adjustments (e.g., rate adjustments, specific line items, etc.). After much debate and based on the belief that errors of this sort are likely to be small, the majority of group members agreed to the following. The difference between actual billed and “true” billing should be periodically calculated and the value stored in a deferral account. When the aggregate amount reaches a predetermined level, it should be cleared and the monies either collected or disbursed according to as equitable a method as possible recognising the practical difficulties of attributing accurate amounts to individual customers for which

the error applies. For example, one LDC might simply rebate or bill all residential customers a fixed amount to address a past error, while another might allocate the error based on historical usage. More detailed implementation guidelines need to be developed in this area.

- There are other sources of errors in the settlement process besides errors in data from the IMO. Included among these are errors resulting from billing customers with manually read interval meters based on their actual load shape even though that load data is not available in time to be subtracted from total system load when developing the net system load shape. (See recommendations for issue VIII.E.1 for further discussion of this issue.) To the extent that these errors can be quantified, they too should be included in the deferral account.
- In coming to the above recommendations, the group agreed that the deferral account is not within the control of an LDC and, therefore, LDCs should neither profit from nor be penalised for such errors through the PBR process. That is, it should not be considered in the same manner as losses or UFE, but should be isolated from these other factors.
- In deciding how to proceed on the issue of using preliminary or final data, it is important to consider the potential for errors occurring elsewhere in the settlement process. It was noted that the NSLS settlement cost-allocation process can produce cross-subsidisation errors in some cases ranging as high as 7 percent (see RTP Report). There will also be errors resulting from distribution loss estimates and UFE.
- Group members generally supported RTP recommendation 3-16, which allows LDCs to issue settlement invoices in accordance with their normal billing cycles. The implication of this is that retailers will receive bills from LDCs on a daily basis covering a portion of the customers they serve in an LDC's service territory. The group discussed the fact that some retailers would ideally want LDCs to issue invoices for all customers at the same time (logically monthly) but all recognised that this was unrealistic given the way in which settlement is being designed in Ontario as a logical extension of the normal billing cycle. It was also noted that the cyclic nature of billing by LDCs offers a value-added service opportunity for retailers who serve multisite accounts to manage billing and cash flow for such customers.
- In considering the issue of heterogeneous billing cycles by LDCs, the group took under advisement the concern of subgroup 1 that bimonthly or longer billing cycles could increase the magnitude of prudential requirements for retailers. However, the group felt that retailers could effectively manage the cost of prudential requirements by billing their customers more frequently than they are billed by LDCs. For example, even if an LDC only bills every 60 days and requires that retailers post security in an amount equal to two billing cycles, retailers can keep their costs down by billing customers every 30 days (based on estimates). Thus, a preliminary recommendation by subgroup 1 that invoices be issued every 30 days by all LDCs was rejected by the settlements subgroup.
- The group also discussed whether there was a need to require a common methodology across all LDCs for estimating usage when bills are issued without a meter read. The subgroup saw no need for a uniform approach as long as whatever approach is used is transparent and disclosed to all retailers upon request.

RECOMMENDATION:

1. LDCs should be allowed to bill retailers according to their normal meter-reading and billing cycles. In order to minimise the lag in issuing bills to retailers, LDCs must determine bill amounts based on preliminary price and system load data issued by the IMO ten business days after the consumption date.
2. Contemporaneous reconciliation of customer bills, which requires completing 100 percent of the meter reads in a settlement area, is not required nor allowed.
3. Periodically, differences between the amount billed in aggregate using preliminary data and the amount that should have been billed as determined using the currently most accurate data must be calculated. (The method of calculating this is described in recommendations for issue VIII.D) These differences, positive or negative, will be kept in a deferral account. Periodically, the deferral account must be cleared through rebates or charges on future bills. LDCs will be allowed some discretion regarding the precise method that will be used to allocate the deferral amounts to individual customers. For example, the amounts could be allocated to all customers, only to customers in a specific class (e.g., only to kWh metered customers if errors arose from the NSLS calculation rather than from market price errors) or through some other equitable scheme. Because of the practical difficulties of doing so, the amounts do not need to be allocated only to those customers who were erroneously billed in the first place.

IMPLEMENTATION ISSUES:

Guidelines/requirements must be developed regarding the calculation of the amounts that may be placed in the deferral account and the allowable methods for disbursing/collecting deferral amounts.

VOTER SUMMARY:

The majority of Task Force members voted in favour of the recommendations. Several Task Force members favoured allowing LDCs the option of using either the preliminary data or waiting until final statements are issued by the IMO.

DISSENTING OPINIONS:

Note the dissenting opinion mentioned above regarding mandatory versus voluntary use of preliminary data.

ISSUE STATEMENT: (Final)

Global Issue Outline VIII.B: Retail Settlement Areas

- How should geographic/electrical connection areas be defined for purposes of calculating the NSLS and average price for use in retail settlement, both prior to and following implementation of congestion pricing?
 - Can/should an LDC have more than one settlement area?
 - Can several LDCs combine their settlement areas?

OPTIONS:

Prior to congestion pricing:

1. Define settlement zones according to distribution license boundaries.
2. Define settlement zones according to electrical connectivity (e.g., distribution systems that are electrically connected or connectable may/should have a common settlement area).
3. Define settlement zones according to a combination of license boundary and connectivity (e.g., a company with a single license that has distribution areas that are not connected or connectable must have separate settlement areas; two companies with separate licenses may not combine settlement areas even if they are connected or connectable).
4. Allow any combination of companies to use a common load shape and average price regardless of license conditions or connectivity in order to reduce settlement-processing costs through outsourcing or joint venture relationships.
5. Same as option 4 but only if average prices using the combined NSLS do not differ from the average price using an LDC-specific load shape by more than X percent.

Following implementation of congestion pricing:

1. If congestion pricing is zonal, mandate that LDCs use the NSLS and hourly prices for the zone in which they are located (with exceptions/adjustments for LDCs whose distribution systems operate across multiple congestion zones).
2. Only mandate use of the zonal price, while allowing LDCs within a zone to either use the zonal NSLS or a different load shape based on one of the five options used prior to implementation of congestion pricing (e.g., one of the five options outlined above).
3. If congestion pricing is nodal, mandate that each LDC assign each customer to a specific node and use the price associated with the assigned node to calculate customer bills. The NSLS used for the customer could be any of the five options outlined above.
4. If congestion pricing is nodal, allow an LDC, at its own discretion, to assign customers to each node as in 3 above or to calculate a load-weighted average price for the settlement area and use a NSLS as defined in one of the five options above.
5. Mandate use of option 3 only if the price differences across nodes within a distribution territory is greater than X percent.

6. Mandate use of option 3 and require that the NSLS be based on supply at the nodes and the interval-metered customers assigned to that node. In other words, determine the NSLS by node.

BACKGROUND INFORMATION:

The RTP did not explicitly explore the issue of settlement area. The implicit assumption underlying RTP recommendations 3-4 and 3-6 is that each LDC would constitute a separate settlement area, at least in terms of having a unique NSLS and unique loss adjustments.

Locational marginal pricing (or congestion pricing) is scheduled to occur 18 months after the market opens. Whether this will be implemented as zonal pricing or nodal pricing is uncertain at this time. Nodal price information will be gathered at the outset of market opening and used to determine how or if congestion pricing will be implemented in the future. It is not currently known where price differences across nodes or zones are likely to be significant.

GROUP DISCUSSION:

The issue of the appropriate settlement area was discussed at length at several meetings.

The primary driver for defining a settlement zone is accuracy in cost allocation. If energy costs differ significantly across two areas, economic efficiency will be improved if those differences are reflected in the prices charged to consumers/retailers operating in each area. Costs will vary if there are differences in the wholesale hourly prices being charged in each area, if the usage patterns of consumers located in each area differ and if losses vary across areas.

Prior to implementation of congestion pricing, prices charged at all supply nodes in the province will be the same. Thus, nodal prices are not a factor in selecting settlement zones in the short run but may be an important driver in the long run if prices vary significantly across nodes. In the latter case, averaging prices across multiple nodes within a specific settlement area would distort price signals and lead to inefficient locational decisions by generators and new customers and inefficient usage decisions by existing customers. If price differences are not large, averaging may still be preferable when compared with the added cost of creating multiple settlement zones. Of course, what constitutes a “large” difference is a judgement call.

Differences in losses across distribution companies can be significant, ranging from one or two percent to seven or eight percent or higher. Unless loss adjustments vary hourly, the load-weighted average price estimated using the NSLS will be the same regardless of the loss factor. If an LDC decides to develop hourly loss factor estimates, then the load-weighted average price will differ before and after loss adjustment. However, given the analysis reported on below, it is unlikely that the difference in the average price due to differences in loss adjustment factors will be significant. Whatever decision is made about settlement areas, loss and UFE adjustments to energy usage should be LDC specific. However, distribution losses and UFE adjustments should have little bearing on whether or not a common NSLS can be used across LDC service territories when calculating average prices.

Thus, the issue of what geographic boundaries, if any, should be established for determining the NSLS to be used in settlement calculations comes down to whether or not there are significant differences in the load-weighted average price across geographic boundaries due to differences in usage patterns as reflected in the NSLS. To examine this issue, OHSC staff volunteered to calculate typical bills for small customers using the NSLS for eight different geographic areas and to compare the values with an estimate based on the aggregate NSLS across all areas. Each of the eight zones represented between 4 and 25 percent of OHSC’s total energy consumption.

Customer mix and climate differ across areas as does the percent of load attributable to interval-metered customers, which ranged from 2 to 16 percent. The analysis was done using three different price curves: 1997 RTP II prices from Ontario; 1997 PJM pool prices; and 1998 Alberta pool prices. Monthly average prices (\$/MWh) are presented in Table 1 below and the annual cost estimates for customers with different levels of consumption in each zone are presented in Table 2.

As seen in the tables on the next page, differences in prices and annual bills for low-volume customers appear not to be very sensitive to differences in the NSLS, at least within the range reflected in OHSC's eight zones. Looking at annual average prices, the largest discrepancy is for zone 4, which is 1.7 percent less than the average across all zones. The biggest discrepancy on a monthly basis is in January, where the average price using the zone 5 NSLS is almost 6 percent less than the average using the NSLS for all eight zones. However, in most months, the differences are much smaller across all zones.

As seen in Table 2, the difference in customers' annual bills is quite small when calculated using the zone-specific and the multizone average, typically amounting to only a few dollars and, quite often, being less than \$1 on an annual bill of several hundred dollars or more. In all cases, the difference is less than 2 percent.

Based on this analysis, it is difficult to argue against allowing LDCs to use a common NSLS across multiple distribution territories for settlement purposes, at least prior to implementation of congestion pricing. One concern is that this approach will introduce some inaccuracy in the settlement process in that the amount collected using an average load shape across multiple regions will differ from the amount that would be collected if the local LDC load shape were used (it could be higher or lower). However, the analysis discussed above suggests that the difference will not be large. A related concern is whether using a multiarea load shape might significantly increase average prices to customers in one of the LDC's territories. For example, it is possible that a small LDC with a particularly flat load shape might find a significant increase in average price for NSLS customers if it combined forces with several other LDCs and used a common NSLS. This could lead to customer complaints to the OEB. One means of countering this possibility would be to establish a rule that LDCs can combine and use a single NSLS for settlement purposes unless doing so increased the average price for an LDC by more than X percent.

Table 1
Monthly Average Prices (\$/MWh) by Zone and Price Curve

Zone	1997 RTP II (Ontario)	1997 PJM Pool	1998 Alberta Pool
Zone 1			
Zone 2			
Zone 3			
Zone 4			
Zone 5			
Zone 6			
Zone 7			
Zone 8			
Average			

Table 2
Annual Billing Difference Between Zone-Specific and Multizone Average Settlement Using RTP II

Zone	Zone-Specific Settlement	Multizone Average Settlement	Difference (\$)	Difference (%)
Zone 1				
Zone 2				
Zone 3				
Zone 4				
Zone 5				
Zone 6				
Zone 7				
Zone 8				
Average				

RECOMMENDATIONS

1. Prior to implementation of congestion pricing, when calculating the load-weighted average price for kWh-metered customers using the NSLS, LDCs should be allowed to use a NSLS based on the net load across multiple distribution areas without regard to license boundaries or electrical connectivity. Adjustments for distribution losses and UFE should still be estimated individually for each LDC service territory.

2. When making business decisions regarding whether or not to combine with other LDCs, analysis should be done to determine whether doing so will increase the average price paid by customers whose settlement costs are calculated using the NSLS. If the average costs increase by more than X percent, approval must be obtained from the OEB. Retailers must receive sufficient notification concerning an impending change in the load shape being used for settlement calculation by an LDC so that they may voice any concern to the OEB prior to approval of the change.
3. New rules pertaining to the ability of multiple LDCs to use a common NSLS for settlement purposes will be considered once a determination is made concerning congestion pricing. If congestion pricing is implemented, it is possible that certain combinations will no longer be allowed or that multiple settlement zones may be necessary even within a single LDC's license boundary. It may eventually be necessary to assign each customer within an LDC's service territory to a particular settlement zone or congestion node. LDCs should consider this possibility when implementing software and systems changes for initial market opening.
4. The above recommendations apply to settlement for non-interval metered customers. Settlement for interval-metered customers should not be affected by the decisions made regarding whether or not to combine multiple territories for purposes of calculating the NSLS and average price.

IMPLEMENTATION ISSUES:

What historical prices should be used and precisely what analysis should be conducted in order to test whether combining with other LDCs will increase prices by more than X should be outlined. The value of X also needs to be determined.

VOTER SUMMARY:

Sixteen in favour; none against.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: (Final)

Global Issue Outline VIII.C.1: Determining Network Losses and Unaccounted for Energy

- ♦Should network losses and UFE be treated as a single item or should separate estimates be developed?
- Should UFE be applied to customers who install interval meters or only to those whose costs are allocated using load profiles?
- Should wholesale and retail customers be treated the same with regard to losses and UFE or treated differently?

OPTIONS:

1. Combine losses with UFE for all customers
2. Combine losses with UFE only for NSLS customers
3. Develop separate estimates for both NSLS and interval-metered customers

BACKGROUND INFORMATION:

- MDC Final Report, section 6.2.1.
- RTP Report, sections 3.2.2 and 3.2.3.

SUMMARY OF GROUP DISCUSSION:

- Developing separate estimates of losses and UFE is extremely difficult. The two combined can be easily estimated annually by simply subtracting end-use metered loads from total system load. (See issue VIII.C.2 and 3 for further explanation of how losses and UFE will be estimated.) Apportioning this total to losses and UFE requires much more sophisticated modelling and estimation techniques.
- Interval metered customers often claim that they should not be allocated UFE because their load is being accurately measured. However, accuracy is relative since their loads must, at a minimum, be adjusted for losses. Even if one agreed in principle that interval-metered customers should not pay for UFE, the practical difficulties noted above make implementation of the principle difficult and/or extremely subjective.
- Even if 100 percent of customers had interval meters, UFE would still exist due to meter errors. In this event, who would pay for UFE if it was not combined with losses and attributed to all customers, including interval-metered customers?

RECOMMENDATION:

1. Initially, combine Network Losses and UFE into a single estimate and apply the estimate to both interval-metered and non-interval-metered customers. However, in recognition of the possible development of separate estimates and the possible ruling by the OEB that interval-metered customers should not be charged for UFE, LDCs should develop settlement system

software to accept separate estimates for losses and UFE and separate usage of these estimates for interval and non-interval metered customers.

2. Wholesale and retail customers should be treated equally with respect to losses and UFE.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: (Final)

Global Issue Outline VIII.C.2 and 3: Determining Network Losses and Unaccounted for Energy

- What methodology should be used to calculate network losses and UFE?
- Should losses and UFE be accounted for as an uplift on energy or as a wires charge?

OPTIONS:

Determination of losses:

1. LDC system average
2. Flexibility to handle loss factors by hour, class and/or voltage level

Collection of losses:

1. Through fixed distribution charge
2. Through energy charge

BACKGROUND INFORMATION:***Relevant RTP Recommendations:***

RTP Recommendation 3-6:

DLF and UFE estimates should be developed for each individual LDC in order to reflect important differences in distribution system design, customer density, metering practices and other determining factors.

RTP Recommendation 3-7:

Two or more methodologies for calculating DLF and UFE parameters that vary with respect to cost and complexity should be approved by the OEB. Each LDC could then select one of the approved methodologies consistent with the magnitude and importance of losses and UFE on its network. The OEB would be obliged to accept estimates based on any of the approved methods, subject to the right of the OEB to audit implementation of the methodology.

RTP Recommendation 3-8:

At least one of the OEB-approved methodologies should reflect the reality that losses vary with load and voltage. That is, separate estimates should be made for customers connected at subtransmission, primary and secondary voltages on a distribution system. Implementation of this methodology would require that LDCs have information in their CIS systems that identifies the voltage level at which each customer is served and bill calculation software that could accommodate hourly DLF and UFE estimates.

DRAFT PBR RATE HANDBOOK

The draft PBR rate handbook is likely to recommend rate unbundling with the following

characteristics:

- A simple approach for the first three years of the market.
- Determination of revenue by class based on existing rates.
- Estimation of wholesale supply costs that includes, as it has in the past, generation, transmission and distribution losses.
- Estimation of distribution revenue requirements by class equal to total revenue minus wholesale supply costs.
- Distribution revenue requirements by class being collected equally on a per customer basis for residential customers. For general service and large use customers, a portion of distribution revenue may be collected based on demand.
- Estimated wholesale supply costs collected based on kWh usage.

SUMMARY OF GROUP DISCUSSION:

- Some members indicated a preference for including loss adjustments in the wires charge rather than as an uplift on energy.
- There is general agreement with RTP recommendations 3.6, 3.7 and 3.8.
- Retailers might be concerned about having to deal with different loss calculations across different LDCs. A completely retailer-friendly market would probably have a single estimate across the entire province. However, this would lead to over collecting settlement obligations for some LDCs and under collecting them from others.
- A suggestion was made that the more complex loss estimation method include seasonal variation in losses and different estimates for peak and off-peak periods (i.e., up to 24 loss factors per year). The group agreed that the more complex method should simply involve allocation of the annual value calculated as described below across customers, hours or whatever determinants are appropriate. In the end, the same amount should be collected annually as if it were collected using the simple method.
- The simple method should be an annual estimate applied to all customers. Originally, the group recommended calculating a 5-year rolling average using the formula contained in the recommendations below. Several reviewers indicated that the draft Rate Handbook recommends using, at least initially, a five-year average, rather than a rolling average. This recommendation is intended to give LDCs an incentive to reduce actual losses and UFE under the PBR rate cap.
- Some LDCs were concerned about the difficulty of calculating losses separately for each settlement area, if a settlement area is smaller than an LDC's entire service territory. For example, if OHSC is divided into several settlement areas, each requiring individual loss adjustments, it would be difficult to obtain the historical data necessary to calculate a five-year average. There was agreement in principal that a utility that is broken up into separate settlement zones should be allowed to determine losses based on less than a five-year average up until the time that five years of data are available by settlement zone. That is, there would not be a need to reconstruct historical data by settlement zone if it does not easily exist. The group did not discuss how to reconcile this principal with

the intent of the PBR mechanism to provide an incentive for LDCs to reduce losses over time by holding the allowed loss adjustment constant over the PBR rate period.

- Losses for embedded generation are those losses associated with delivering power to the distribution system. Typically this would be the losses associated with the generator step-up transformer. If the generator is low voltage metered the adjustment for the NSLS calculation would involve reducing the output of the generator by the transformer losses. It was recognised that each situation could be unique but this was an acceptable general approach. If a LDC wants to estimate customer-specific transformer losses, it should have the option to do so.
- The IMO requires a DLF estimate to calculate usage for embedded wholesale market participants. The IMO has concerns about being able to accommodate complex loss adjustment mechanisms developed by LDCs.
- It is assumed that a Primary Metering adjustment will still be included in the rate structure.

RECOMMENDATION:

1. The OEB will approve one methodology for calculating losses using a single annual loss factor based on a five-year average using the following formula:

$$\text{Losses} + \text{UFE} = E_{in} B [(.99)E_p + E_s + \text{UM}]$$

$$\text{Loss adjustment factor} = [\text{losses} + \text{UFE}]/E_{in}$$

where E_{in} = total settlement area load measured at all grid supply points feeding a distribution area plus all wholesale and retail generation connected to the distribution wires

E_p = total load for primary metered customers measured at the customer meter

E_s = total load for secondary metered customers measured at the customer meter

.99 = an adjustment for losses associated with transformation from primary to secondary service

UM = estimated consumption for billed but unmetered load.

This calculation includes network losses inclusive of the losses and the primary transformation down to the utilisation voltage of a customer. An alternative approach would be to calculate losses up to the primary transformation level. This is acceptable as long as it is mathematically equivalent to the above formula.

2. In the event that an LDC does not have five years' worth of relevant data to use in developing an estimate, the OEB will consider exceptions to the above rule.
3. Subject to OEB approval, each LDC should have the option to compute losses based on an alternative methodology that allocates the five-year average annual loss factor to time-periods and customers based on several factors, including time-of-use, customer class and/or voltage level. The allocation process must be non-discriminatory within customer classes. In order to obtain OEB approval, an evaluation of the additional cost to accommodate the alternative within the settlement system would be required. In approving any complex methodology, the OEB should take into consideration the IMO's ability to

incorporate the complexity into its settlement calculations for embedded wholesale market participants. It should be recognised that the IMO systems and processes will be designed, developed and implemented to accommodate a single loss factor for each embedded market participant. More complex methods should be tested through the IMO prior to implementation and LDCs should bear any incremental cost associated with IMO implementation of these methods.

4. Customers who are primary-metered should not pay for transformer losses. Primary meter adjustments can be made using either a factor of 1 percent (the standard currently used in the province) or an alternative site-specific adjustment factor if data are available to support development of better estimates.
5. To be consistent with the draft rate handbook, it is recommended that distribution losses and UFE be collected as an energy uplift on all consumption.

IMPLEMENTATION ISSUES:

The OEB must approve exceptions to the basic rule on loss calculations.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: (Final)

Global Issue Outline VIII.D: Calculating NSLS

- How should the NSLS be calculated?
- Should certain customers (e.g., those above a specific size) be required to install interval meters rather than have their commodity bills calculated using the NSLS?

OPTIONS:

The recommendations presented below describe a step-by-step process that produces correct cost allocation estimates using the NSLS methodology. Individual LDCs may use different procedures and calculations as long as they produce mathematically equivalent estimates.

BACKGROUND INFORMATION:**RELEVANT RTP RECOMMENDATIONS:**

RTP Recommendation 3-4:

Each LDC is responsible for calculating a NSLS profile for use in determining average electricity costs for all customers who do not have interval data recording meters capable of measuring hourly usage. In calculating the NSLS, loads associated with embedded wholesale customers, embedded wholesale generators and interval-metered customers with remote meter reading capability, all adjusted as determined by the OEB for losses and UFE, should be subtracted from the total system load attributed to the LDC.

RTP Recommendation 3-9:

Adjustments for losses and UFE should not be based on contemporaneous reconciliation to total system losses. Reconciliation involves calculating the difference between the sum of all individual hourly loads, adjusted for losses and UFE and the total system load and allocating this difference back across the individual loads. As an alternative, the RTP recommends that aggregate error be calculated on an annual or biannual basis and that periodic adjustments are made in distribution loss estimates and UFE. The RTP does not recommend billing for historical “true-ups” associated with any residual error determined through this periodic evaluation.

RTP Recommendation 3-12:

Because of the small number of existing TOU meters in the province and the low incremental cost of new interval meters compared with new TOU meters, the RTP does not recommend that LDCs be required to calculate bills for these customers based on TOU period-specific usage values. However, LDCs should be allowed to do so on a voluntary basis. The OEB should decide how the incremental cost of the software development and data processing required to support this special treatment should be recovered.

RTP Recommendation 3-5:

Average prices used to determine bills for unmetered loads should be calculated using the NSLS

rather than any independently derived load shape estimate.

RTP Recommendation 5-19:

Remotely read, hourly interval meters should be read weekly. The weekly interval would be midnight on Sunday to midnight the following Sunday. By noon on the first business day after Sunday (for most weeks this will be Monday), 80 percent of the hourly interval data for the prior week, for which an MDMA is responsible, must have undergone VEE and be posted on the MDMA's Web site. Irrespective of what day is the first business day after Sunday, by noon on Thursday, 100 percent of the hourly interval data for the prior week, for which an MDMA is responsible, must have undergone VEE and be posted on the MDMA's Web site.

Note: These meter reading and VEE standards apply regardless of whether or not remotely read meters are read by third-party MDMA's or by LDCs acting as MDMA's.

MDC Recommendations, Second Interim Report

MDC Recommendation 4-16:

We recommend that the market rules not require the installation of interval meters for customers who switch electricity supplier, nor for customers of any particular size. Local distribution companies retain the right to require interval metering for customer classes as they believe necessary to collect billing-determinant data for OEB-approved tariffs. However, if interval metering is required for a particular class of customers connected to an LDC, it will be required of all customers in that class, whether they buy electricity from the LDC or from a competitive supplier. LDCs shall not require the installation of interval metering as a precondition for switching to a competitive supplier.

MDD Recommendation 4-17:

We recommend that if a customer switches to a competitive supplier without installing an interval meter, the load profile used to estimate the customer's load shape must be the same profile that would be used if the customer had not switched.

SUMMARY OF GROUP DISCUSSION:

- Issue VIII.C addresses the issue of what geographic or electrically isolated area settlement should be determined on. All settlement calculations described below should be done for a settlement area, which may or may not coincide with the geographic boundary of an LDC's license.
- Issue VIII.A.3 discusses the settlement time line and the mandatory use of preliminary IMO data rather than final IMO data when determining settlement for retailers. In reality, there is the possibility of errors being discovered in the system load or wholesale price data regardless of whether preliminary or final data are used for initial settlement. Thus, a process must be developed for determining whether such errors have occurred and for debiting or crediting bills if errors are large. The group discussed many ways of addressing this problem. One approach required keeping preliminary databases for each billing cycle (e.g., which would mean a different database for each business day) for an extended period of time in order to provide an audit trail. Another approach required keeping only a single preliminary database but involved billing future customers using preliminary data that was known to be in error in order to keep the audit trail clean. A third approach, the one ultimately agreed to, involved updating the billing database with the best available data at any point in time. This does not provide a perfect audit trail but

it bills customers according to the best available data and reduces storage and processing complexity. With this approach, aggregate errors can be determined at any point in time by calculating the aggregate revenue based on the best available data and comparing that aggregate value to the amount billed over any period of time. The difference can then be placed in a deferral account and periodically collected from or rebated to customers according to an agreed formula.

- The subgroup discussed a variety of issues associated with settlement for Standard Supply Service (SSS) customers. Although pricing and invoicing of end-use customers will vary with the nature of SSS, cost allocation calculations using the NSLS are the same regardless of the form of SSS. (See Issue VIII.E.10 for further explanation.)
- The subgroup noted that the use of the NSLS provided no price signal for load shape customers to alter the timing of their consumption either for environmental or cost control reasons. Of course, this is true of any settlement or pricing approach that does not involve TOU or interval metering.
- The subgroup discussed whether cost-allocation calculations for TOU-metered customers should differ from those of kWh-metered customers, either as a mandatory obligation for all LDCs or on a voluntary basis. The group noted the lost incentive for load management strategies if TOU meters are not accommodated by the settlement process. (See Issue VIII.E.5 for further discussion.)
- The subgroup also discussed whether customers with selected characteristics should be required to install interval meters rather than have their costs allocated based on the NSLS. Among the options discussed were:
 - All customers > 100 kW.
 - Any customer with load > 10 percent of the LDC total load.
 - Allow LDCs to set their own meter standards, as long as they are not discriminatory among SSS and competitive customers.

RECOMMENDATION:

Calculating the NSLS:

Below is a step-by-step procedure that produces the correct cost allocation estimates for customers with non-interval meters. Any deviations from the process described must be shown to produce mathematically equivalent estimates.

Step1. Ten business days after each trading day, LDCs will receive from the IMO the following preliminary information, which should be loaded into the billing database, B:

The aggregate quantity of energy (in MWh) supplied each hour to the distribution system, adjusted for the amount delivered to embedded wholesale customers (adjusted for losses and UFE based on LDC-specific values) or injected into the distribution system by embedded wholesale generators.³

³ It is noted that LDCs will also require access to embedded wholesale customer data in order to bill for wires services and to determine losses at the end of each year by comparing total system load and end-use metered load for all customers connected to the distribution system.

The aggregated quantity of ancillary services purchased.

Hourly peak demand.

The relevant prices that the IMO has applied to each of its settlement calculations (\$/MWh).

Applicable transmission service charges.

Total charges and prices for all uplift and IMO administration charges.

(It is noted that certain charges, such as fixed transmission and IMO administration charges, may only be provided monthly or, perhaps, even less frequently. These variables should not affect the NSLS calculation nor the commodity bill calculation, but they must be included on invoices to customers and retailers.)

Step 2: Twenty days after each trading day, “final” values for the items identified in Sep 1 will be provided by the IMO. It is also recognised that at some later point, if an error is discovered, corrected data will be provided by the IMO. Whenever updated information becomes available, it will be loaded into database B, replacing any previously incorrect data that might have existed at the time of billing.

Step 3: On a weekly basis, acquire VEE data from remotely read interval metered retail customers. Store the data for use in calculating the NSLS in Step 4. As noted in RTP recommendation 5-19, 100 percent VEE data should be available either from an LDC’s meter-reading department or from an external MDMA no later than four days after the read day (e.g., meters are read on Sundays and data are available on Thursday).⁴ Thus, worst-case scenario is that data for a specific trading day is available 12 calendar days after the trading day. This frequency and timing are sufficient since IMO data for the same trading day are not available until ten business days or roughly 15 calendar days, after the trading day.

Step 4: On a daily basis, the NSLS is calculated as described below using the preliminary information obtained in Step 1.

Acquire hourly data for all remotely read, interval meters from the database created in Step 3. Also acquire data for unmetered loads being settled based on “virtual” interval meters (see streetlight discussion below).

For each hour, subtract the total system losses (network element losses and UFE) from total system load.

For each hour, subtract the interval-metered data for retail load customers from total system load.

On an hourly basis, if applicable, add interval-metered data for embedded retail generation (i.e., not embedded wholesale generators) to the previous amount to produce the net system load. If the retail generator is not interval metered, use the NSLS. Retail generation loads should be adjusted for site-specific losses that occur between the point of generation and the point of supply to the distribution system. The specific adjustments will depend on where the generator is located and whether it is connected at primary or secondary voltages.

⁴ Some reviewers noted the potential difficulty of having VEE data available in such a short period of time and suggested that the MDC’s recommendations in this area might need to be revisited.

The NSLS data calculated as above should be loaded into the billing database, B.

IMPLEMENTATION ISSUES

Determining how to calculate the deferral account.

VOTER SUMMARY

Unanimous.

DISSENTING OPINIONS

None.

ISSUE STATEMENT: (Final)

Global Issue Outline VIII.E.0: Calculating customer/retailer commodity bills for kWh-metered customers using the NSLS

OPTIONS:

See comments below regarding mathematically equivalent methodologies.

BACKGROUND INFORMATION:

See recommendations for issue VIII.D regarding calculation of the NSLS.

SUMMARY OF GROUP DISCUSSION:

There was significant discussion around the issue of cycle billing versus event billing. Cycle billing is the practice employed by many utilities that assumes that all meters read according to a specific read route are read on a single day, even though there is some variance around that day. For example, the target date for a specific read cycle might be January 10, but the meters in this read cycle might actually be read on January 9 or 11. In general, the variation across read cycles is two to three days. Some subgroup participants claimed that it would be very difficult and costly to modify their systems to bill based on events (e.g., actual read dates) rather than to cycle bill. Cycle billing will introduce some error into the settlement calculation in that the average price, which varies daily, will not be completely precise for the billing period if the exact days in the billing period differ from the days assumed for the read cycle. However, this error will be extremely small, much smaller, indeed, than other errors in the settlement process. Therefore, it was agreed that cycle billing would not be encouraged, but would be allowed if the cost of changing to event billing was significant.

RECOMMENDATIONS

The following step-by-step process should be used to determine the commodity portion of bills for customers/retailers served using kWh meters:

1. For any given billing period (defined as starting at midnight of the first day and ending at midnight of the last day), acquire the net system hourly loads by accessing database B referenced in Issue VIII.D.
2. Determine a weighted average price for the period by multiplying the hourly net system load times the hourly price, summing the product of price and load for all hours in the billing period, and dividing the sum by the total net system load for the period.⁵ (*Note: The issue of gross versus net billing must be clarified in order to confirm the validity of this price calculation.*)
3. For any given customer, adjust the metered (or estimated) consumption for the period for losses and UFE.

⁵ A mathematically equivalent approach would be to calculate daily average prices based on a load-weighted average price for the day and then weight the daily averages for a billing period by the share of total usage during the period that occurs on each day. This approach may be more efficient from a data processing standpoint.

4. Multiply the weighted average price and the adjusted consumption to determine the cost of energy and pass the value to the billing process for inclusion on invoices along with wires and other charges.
5. If required by retailers, provide NSLS factors for the period to allow retailers to allocate their customer's load to individual hours in order to support bilateral contracts with suppliers.
6. Periodically (perhaps quarterly or annually) an LDC should calculate the aggregate revenue that should have been collected from customers using the best available data stored in B. This value should be compared with the amount actually collected. Any difference will be accumulated in a deferral account and periodically collected or refunded according to the guidelines delineated in recommendations for issue VIII.A.

IMPLEMENTATION ISSUES:

The final step should be investigated further. The recommended approach may be problematic in light of customer churn and movement from NSLS to interval metering.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: (Final)

Global Issue Outline VIII.E.1: Calculating Customer Commodity Bills for Interval Metered Customers

- How should bills be calculated for customers with interval meters that can be read frequently enough to include the data in the calculation of the NSLS?
- How should bills be calculated for customers with interval meters that are read less frequently and for which data is not available in time to be used in calculating the NSLS?

OPTIONS:

Option 1(A): Interval-metered customers whose meters are read in time for the data to be available within settlement time frame (generally with AMR) must be billed using their interval-metered data and the hourly spot price. The interval-metered data from these customers must be used in the calculation of the NSLS to be applied to non-interval customers.

Option 1(B): Interval-metered customers whose meters are read in time for the data to be available within settlement time frame (generally with AMR) should be billed using their interval-metered data and the hourly spot price. The interval-metered data from these customers should be used in the calculation of the NSLS to be applied to non-interval customers.

Option 2(A): Interval-metered customers that are read but whose data is not available within the settlement timeframe (generally non-AMR) would be read during their normal billing cycle. The customers must be billed using the interval data and the hourly spot market price. Due to the latency of the information, the interval data would not be used in the calculation of the NSLS.

Option 2(B): Interval-metered customers that are read but whose data is not available within the settlement time frame (generally non-AMR) would be read during their normal billing cycle. These customers must be billed using the interval data and the hourly spot market price. The interval-metered data from these customers should be used in the calculation of the NSLS to be applied to non-interval customers.

BACKGROUND INFORMATION:

AMR means a meter equipped with a reliable communication interface between the meter and the database (including radio frequency, telephone, fiber and power-line carrier).

RTP Recommendation 5-19 (timing of reading schedules for AMR meters)

RTP Recommendation 3-13:

For all customers above 50KW, where metering services are competitive, interval meters must have remote meter reading capability and meter data management agents (whether the local LDCs or retailers) must deliver the relevant validated data to the LDCs in time to be included in the calculation of the NSLS. Initially for customers below the 50 kW cut off, interval meters that are read manually may be installed and used for individual settlement calculations. If the amount of load using manually read interval meters becomes large, the OEB should reconsider this policy.

SUMMARY OF GROUP DISCUSSION:

- The subgroup supported the principle that LDCs should have discretion in setting meter technical standards including thresholds for installation of interval meters.
- The subgroup discussed the issue of AMR communication link to the meter to expedite data transfer for use in the settlement process.
- Larger customers should be required to have a communication link to ensure that their data is subtracted from wholesale data in the creation of NSLS.
- Should there be a limit or threshold above which an AMR link is required?
- Can customers request a communication link and must utilities comply?
- Will there be any significant NSLS errors introduced by not subtracting the interval data for non AMR connected meters—it would depend on threshold levels of who is required to have AMR link.
- LDCs should retain the discretion to set levels above which interval meters are required.
- There should be a provision for utilities to correct for errors associated with billing from load interval data but not subtracting it from the NSLS calculation. It was suggested that a deferral account be used to track differences. Issues around allocation of the deferral account are discussed elsewhere.

RECOMMENDATION:

1. Interval-metered customers whose meters are read and the data made available within the settlement time frame (generally with AMR) must be billed using their interval-metered data and the hourly spot price. The interval-metered data from these customers **must** be used in the calculation of the NSLS to be applied to non-interval customers.
2. Interval-metered customers whose meters are read but the data is **not** available within the settlement time frame (generally non-AMR) must be billed using the interval data and the hourly spot market price. Due to the latency of the information the interval data would not be used in the calculation of the NSLS.
3. For all customers above 50 KW who have interval meters, the meters must read and the data validated in time to be used to produce the NSLS. Typically, this would mean that these meters must be capable of being read remotely. Initially for customers below the 50 kW cut-off, interval meters that are read manually may be installed and used for individual settlement calculations. If the amount of load using manually read interval meters becomes large, the OEB should reconsider this policy.
4. Settlement errors resulting from billing manually read interval-metered customers based on load that has not been subtracted from the NSLS will be determined periodically and may be maintained in a deferral account and periodically collected from or paid to existing customers as described elsewhere.

VOTING SUMMARY:

Unanimous (18 Task Force members in favour)

DISSENTING OPINIONS:

See voting summary.

ISSUE STATEMENT:

(Note: This issue statement is an addendum to Global Issue Outline VIII.E.1, which concerns calculating customer commodity bills for interval-metered customers. This issue was voted on final by the Task Force. However, one of the recommendations associated with Issue VIII.E.1 was that all customers with demands above 50 kW who have interval meters must have interval meters that are read in sufficient time to be included in the NSLS calculation. Missing from that recommendation was a definition of what constitutes a 50 kW customer. This issue is addressed below.)

After voting favourably on the recommendations below, it was decided that the issue should be included in the Distribution System Code, not the Settlement Code.

- What is the practical definition of a customer with demand exceeding 50 kW?

OPTIONS:

1. Base the qualification only on measured peak demand, using either an average over some period of time or the highest or lowest peak over a period of time. Note that this option would eliminate all customers who did not previously have either a demand meter or a manually read interval meter.
2. Develop an estimate of likely peak demand based on consumption and an assumed load factor.

BACKGROUND INFORMATION:

The RTP addressed the issue of defining the 50 kW threshold in the context of determining who is eligible to receive competitive metering services. While the issue being addressed here concerns identifying customers for which remotely read interval metering is mandatory if interval metering is installed, the issues associated with defining the 50 kW threshold are the same. The following discussion is reproduced verbatim from the RTP final report.

Recommendation 4-18 in the MDC Second Interim Report provides that meter services should be made competitive for customers over 50 kW. There are different ways to define “over 50 kW.” The issue is a common one, since utilities routinely must interpret similar criteria for the purpose of determining customer eligibility for particular rate classes. There is no common utility interpretation of such criteria. The subpanel concluded that for purposes of eligibility for competitive meter services, there should be a consistent definition province-wide.

In fashioning a consistent approach to determine customer eligibility for competitive meter services, the subpanel was guided by the following objectives:

- An approach that would expand rather than limit the market for competitive meter services is preferable.
- There should be a similar outcome for similarly situated customers.
- The approach should be clear and easy to implement.
- The approach should not discourage efficient energy use in order to maintain eligibility for competitive meter services.

The subpanel agreed that eligibility should be determined on a meter-by-meter basis. In accordance with MDC guidance, an eligible meter is:

1. A meter for a load with an average peak over the previous 12-month period greater than or equal to 50 kW.⁶
2. A meter for a load with an average energy consumption over the previous 12-month period greater than or equal to 12,500 kWh per month.
3. A meter for a load that has been previously determined to be eligible for competitive meter services.
4. A meter for a new load for which there is reasonable evidence that criteria 1 or 2 will be met.

One important implication of the recommended approach is that a customer with many separately metered accounts under 50 kW does not qualify for competitive meter services by virtue of its aggregated size. The subpanel grappled with this result since it reduces the size of the competitive market for meter services and is hence counter to one of the subpanel's stated objectives. Nonetheless, the subpanel recommends the per-meter determination because:

- It is the easiest to implement. Any other approach creates difficulties in interpreting who is a "customer" for purposes of determining eligibility for competitive metering. For example, in the case of a franchise chain, would the "customer" be the chain or individual franchisees? In the case of a university, would the "customer" be the entire university or a particular campus?
- The subpanel was concerned that any other approach would place smaller businesses at a disadvantage. For example, a mom-and-pop convenience store might not qualify for competitive meter services, whereas its competitor, a franchise convenience store around the corner would.

The subpanel added a kWh-based criterion for eligibility to give full effect to recommendation 4-18 in the MDC Second Interim Report. The subpanel concluded that a sufficient number of customers who are not demand metered do in fact likely peak above 50 kW to merit development of a kWh-based criterion. To select a monthly kWh number for purposes of eligibility, the subpanel reviewed a table of typical usage at different load factors and resulting kW determinations. Assuming a 33.5-percent load factor (the load factor assumption used for small customers in the 50 kW range to determine rate blocks), customers with a monthly usage of 12,500 kWh (150,000 kWh annual usage) peak above 50 kW. Moreover, since the same figure, 150,000 kWh annual usage, has been recommended by the OEB for purposes of defining residential or small commercial customers, use of the 12,500 kWh figure is practical. Thus, in accordance with MDC guidance, the kWh-based criterion of an average monthly usage of 12,500 kWh over the previous 12-month period was chosen.

Having established criteria for eligibility based on peak or energy usage, the subpanel determined that a customer could qualify under either definition. Thus, a customer that is demand-metered but would not qualify based on its average peak demand could qualify based on its kWh usage. The subpanel elected this approach in part because it expands the competitive market for meter services but also to ensure parity among similarly situated customers. Under an alternative approach, a customer with a usage that makes it eligible for competitive meter services that is not demand-metered could be treated differently than a customer with the same usage who has a demand meter if the second customer would not qualify under the kW criteria.

⁶ By average peak the subpanel means the average billing demand peak.

The subpanel concluded that once a customer qualifies for competitive meter services it should not lose this status. The subpanel did not want to discourage energy efficiency for fear that such activity might result in loss of eligibility for competitive meter services. Moreover, logistical difficulties could ensue if customers switch back and forth between being eligible and ineligible for competitive meter services.

Finally, the subpanel addressed the issue of new customers. Again, utilities must routinely evaluate new customer loads to establish service size and rate class based on whatever information is available. The subpanel concluded that the same process should apply for purposes of determining eligibility for competitive meter services. In the event that there is a disagreement on this point between a customer and an LDC, the customer could challenge the LDC's determination before the OEB. The OEB would likely sanction LDCs that systematically made unfavourable initial determinations without adequate evidential support.

RTP Recommendation 5-2

Eligibility to obtain competitive meter services should be defined as:

A meter for a load with an average peak over the previous 12-month period greater than or equal to 50 kW.

1. A meter for a load with an average energy consumption over the previous 12-month period greater than or equal to 12,500 kWh per month.
2. A meter for a load that has been previously determined to be eligible for competitive meter services.
3. A meter for a new load for which there is reasonable evidence that criteria 1 or 2 will be met.

RECOMMENDATIONS:

A customer with demand exceeding 50 kW is defined as:

1. A meter for a load with an average peak over the previous 12-month period greater than or equal to 50 kW of actual usage (not billed kW),
2. Or a meter for a load with an average energy consumption over the previous 12-month period greater than or equal to 12,500 kWh per month.
3. Or a meter for a new load for which there is reasonable evidence that criteria 1 or 2 will be met.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Eighteen in favour; one against.

DISSENTING OPINIONS:

None stated.

ISSUE STATEMENT:

Global Issue Outline VIII.E.3: Calculating Commodity Bills for Demand-Metered Customers

- How should demand-metered customer's commodity bills be calculated?

OPTIONS:

It is not currently expected that wholesale commodity charges will have a separate, explicit charge for capacity reserves or any other demand-related charges. Transmission and distribution charges are likely to have a demand component but these are not considered commodity charges. Consequently, there is no reason for special treatment of demand-metered customers when calculating commodity bills.

BACKGROUND INFORMATION:

See above discussion under options.

SUMMARY OF GROUP DISCUSSION:

The group expressed concern over power factor corrections and penalties but acknowledged that this had more to do with wires charges than with energy.

RECOMMENDATIONS:

Commodity bill calculations should be the same for demand-metered customers as for non-demand-metered customers.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Unanimous.

ISSUE STATEMENT:

Global Issue Outline VIII.E.4: Calculating Commodity Bills for Load Controlled Customers

- How should commodity bills be calculated for separately metered, controlled loads?
- How should commodity bills be calculated for customers who have selected loads controlled that are not separately metered?

OPTIONS:

1. Develop the settlement capability to specifically estimate all controlled loads, regardless of meter type and configuration.
2. Develop the settlement capability to “accurately” handle all separately metered loads, but not loads that are not separately metered.
3. Only treat separately metered loads that have interval meters differently, while settling any other controlled load as if it was not controlled.

BACKGROUND INFORMATION:

Load controls installed and operated by LDCs:

Many Ontario LDCs currently have the capability to switch selected end-use appliances, such as water heaters, on and off using radio signals, “ripple control” technology through the distribution wires, programmable electronic timers and self-contained high-thermal storage tanks. Because of versatility and low installation costs, programmable electronic timers have been the most common water-heater control devices used during the past few years.

To market or gain public acceptance to this effective energy management initiative, LDCs have developed special flat-rate water-heating charges or have provided customers with financial incentives, such as monthly rebates or elimination of water-heater rental fee.

Some LDCs have successfully promoted voluntary load-reduction programs during, on-peak periods, such as the “Save it till eight” program. This program asks customers not to use certain appliance (washer/dryer, dishwasher, iron, etc.) until after the utility’s peak period has ended.

The other form of load control exercised by LDCs involves bilateral interruptible contracts with some large industrial customers. Under these contracts, participating customers are asked to reduce, predetermined load (part of their overall load) during a specific time when an LDC system is about to reach its peak demand for the month. The LDC shares 50 percent of the avoided demand cost with the customer. These contracts are in addition to the existing Demand Discount System (DDS) offered by the Ontario Power Generation Company which will expire on December 31, 2000.

Load controls installed and operated by customers:

Under a traditional rate structure, the demand cost is a substantial component of the overall power costs. In an effort to reduce power cost, consumers have implemented a variety of demand-side measures, including interlocking loads, demand limit controls, defrost cycle controls, thermal heating/cooling storage, programmable battery chargers, etc.

Load-Control Discount (Rate Handbook):

The load-control discount currently offered by utilities is based on a utility's wholesale bill savings resulting from load control. The savings are a result of shifting demand off a utility's peak, thus reducing the utility's wholesale demand cost. The distributor's load control is generally limited to water-heater load control. Part of the utility's savings resulting from water-heater load control is shared with customers participating in the load-control program through a discount on the water-heater rental charge.

Since existing distributor's load-control programs are related to the cost of power rather than demand on the distribution systems, upon retail access, load-control discounts will no longer apply to the distributors' business. However, upon retail access, a distributor could sell load-control services to a customer that has a load-control contract with a retailer. In justifying the load-control rates, the utility would have to demonstrate full cost recovery on the program.

MDC Final Report, Volume 4, page 3-22:

The issue of treating load-controlled end-uses was not considered by the MDC. Consequently, the RTP did not provide a formal recommendation on this issue. However, the MDC suggested that the OEB, through its rate-setting process, should take this issue under consideration.

SUMMARY OF GROUP DISCUSSION:

Treating controlled loads that are separately metered using an interval meter like any other interval-metered load will result in accurate cost attribution.

For separately metered loads that are measured with a kWh meter, it would be relatively straightforward to develop an algorithm that would use only the prices for hours that the controlled load was actually operated in determining the load-weighted average price. In other words, in calculating the average price over a period of time, a value of zero would be entered for the weight for each hour when the load was turned off and the normal NSLS weights would apply for all non-controlled hours. However, as with the argument underlying the recommendations for TOU metering, this type of treatment would entail added development cost for settlement software and special processing of bills. Given the relatively few cases of separately metered load control, the group felt that this should be done on a voluntary, not mandatory basis.

There is no straightforward or particularly accurate method for estimating costs for controlled loads that are not separately metered. There would be a significant amount of cost and regulatory burden associated with developing and implementing a sensible approach. The group did not feel that this effort was justified.

RECOMMENDATIONS:

1. There should be no mandatory requirement for LDCs to develop special treatment for determining settlement costs for load controlled customers.
2. Any separately metered controlled load that has an interval meter will receive accurate cost allocation using the same settlement approach as for any interval-metered load.
3. Settlement costs for load that is not separately metered must be determined as if the load control did not exist.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Sixteen in favour; one against.

DISSENTING OPINIONS:

One member was concerned that this recommendation compromises the environment because it restricts options available to LDCs to control load.

ISSUE STATEMENT: (Final)

Global Issue Outline VIII.E.5: Calculating Commodity Bills for TOU-Metered Customers

- Should all LDCs be required to incorporate the ability to handle TOU metering in their settlement software?
- Should LDCs with a reasonably large penetration of TOU metering currently be required to develop settlement systems to handle the additional information?
- Should LDCs have complete discretion regarding whether or not to develop settlement systems to incorporate TOU metering?
- Should TOU metering be “banned” with respect to future installations in light of the superior information, cost allocation and pricing flexibility associated with interval metering?

OPTIONS:

See above list.

BACKGROUND INFORMATION:

Recommendation 3-12:

Because of the small number of existing TOU meters in the province and the low incremental cost of new interval meters compared with new TOU meters, the RTP does not recommend special treatment in settlement calculations for customers with TOU meters unless those customers are charged for the incremental cost of the software development and data processing required to support this special treatment.

SUMMARY OF GROUP DISCUSSION:

There are several thousand TOU meters currently in the province and its possible that in the future a number of retailers may wish to install these relatively inexpensive meters for their customers in order to obtain the cost reduction benefits of load shifting. Such load shifting has societal benefits and should be encouraged. However, incremental costs must be taken into consideration. The incremental cost associated with handling TOU meters, both in terms of meter reading and properly handling the incremental information in the settlement calculations, is smaller than for either remotely read or manually read interval metering. On the other hand, the incremental cost of an interval meter is not much greater than that of a TOU meter if a new meter is being installed. For utilities that do not currently offer TOU metering, incremental costs would include the cost of new probes for meter reading, the additional time it takes to download TOU versus kWh meter data and the software modifications required to incorporate such data into the settlement process. For a company that already has an active TOU meter program, all but the settlement system development costs are probably already incurred.

RECOMMENDATION:

1. Provision of TOU metering by LDCs and support of settlement based on TOU data should be optional. If such support is requested, LDCs should make a good faith effort to offer such services with the incremental cost paid by those who desire the service.
2. LDCs who currently have active TOU meter programs may continue these programs and may expand them if they wish. Whether or not the incremental cost of settlement software development and processing of TOU data should be covered only by those who use such meters or shared by all ratepayers is a rate matter to be considered by the Board.
3. If an existing TOU meter requires replacement, consideration should be given to replacing the meter with an interval meter if the costs are comparable. However, the meter may be replaced by a TOU meter at the LDC's discretion.

VOTING SUMMARY:

Unanimous (18 Task Force members in favour).

DISSENTING OPINIONS:

None.

ISSUE STATEMENT:

Global Issue Outline VIII.E.6: How should settlement bills for estimated reads be calculated for customers with kWh meters?

OPTIONS:

See below.

BACKGROUND INFORMATION:

There are two common situations in which distributors issue bills based on estimated rather than actual metered usage. The first occurs when a distributor regularly bills customers on a cycle that differs from the meter reading cycle. The two most common scenarios are distributors who bill monthly but read meters either bimonthly or once every three months. Another scenario involves the practice of billing owners of vacation and cottage homes monthly but only reading meters once a year.

The second situation resulting in estimated usage occurs if a distributor is unable to read a meter during the normal meter reading cycle. For some distributors, the incidence of missed reads is quite low. However, for others, who have a large percentage of their meter stock indoors, the percent of missed reads can be quite high.

In both situations, distributors estimate energy use and treat the estimate as if it were an actual read when calculating the electricity bill. When the next actual read is obtained, the amount of energy used to calculate the current bill is determined by calculating total usage since the last actual meter read and subtracting all estimated usage billed since the last actual meter read. For example, if total usage for a two-month period based on actual meter reads equalled 2,500 kWh and a distributor estimated that usage in the first month equalled 1,500 kWh, the customer would be billed in the second month for 1,000 kWh of usage. As long as electricity prices are constant during the entire period, the sum of the two bills will exactly equal the product of price times consumption for the entire period. However, if prices change during the period, there will be a small difference between the sum of the two estimated bills calculated using the net system load shape weighted average price for each period and a bill amount calculated using the net system load shape weighted average price for the entire period.

SUMMARY OF GROUP DISCUSSION:

The most accurate way to address this situation is to require distributors to calculate a bill using the net system load shape weighted average price for the entire period between actual meter reads and subtract off any dollar amounts billed based on estimated usage amounts since the previous meter read. This calculation is depicted in equations (a) and (b) below. However, mandating this approach could be quite burdensome to some distributors compared with an alternative approach that allows a distributor to calculate the current bill using the net system load shape weighted average price for the period since the last estimated bill. This second option is depicted in equations (c) and (d).

Option 1

$$(a) \ CEC_{t,t+1} = (EMR_{t+1} - AMR_t) \cdot AP_{t,t+1}$$

$$(b) \ CEC_{t+1,t+2} = (AMR_{t+2} - AMR_t) \cdot AP_{t,t+2} - CEC_{t,t+1}$$

Option 2

$$(c) \ CEC_{t,t+1} = (EMR_{t+1} - AMR_t) \cdot AP_{t,t+1}$$

$$(d) \ CEC_{t+1,t+2} = (AMR_{t+2} - EMR_{t+1}) \cdot AP_{t+1,t+2}$$

where $CEC_{t,t+1}$ = commodity energy costs covering the billing period from date t to date $t+1$

$AP_{t,t+1}$ = net system load weighted average price during the billing period from date t to date $t+1$

AMR_t = usage based on an actual meter read on date t

EMR_{t+1} = estimated usage on date $t+1$

Subgroup 3 did some analysis to determine how large of a difference there is in the estimated commodity bills for various customers between the two approaches depicted above. Monthly and annual bills were calculated for customers with different annual usage levels (including some small commercial customers) using Alberta, PJM and Ontario RTP pricing (e.g., estimate-read, estimate-estimate-read). Monthly billing with both bimonthly and trimonthly meter reading was simulated. In nearly all cases, the annual difference in the commodity bills using option 1 versus option 2 was less than 2 percent and, in many cases, less than 1 percent.

Based on the above analysis, and in the interest of minimising development and operational settlement costs, the group recommends that both options be allowed.

Another related issue discussed by the group concerned whether a common bill estimation process should be used across LDCs. The group was in agreement that this was unnecessary, but that it is important that whatever estimation method is used be made available for review by retailers and/or customers.

RECOMMENDATIONS:

1. When determining bills based on estimated reads, when an actual read becomes available, an LDC has the option to issue the current bill based either on the methodology depicted by equations (a) and (b) above or on the methodology depicted by equations (c) and (d).
2. When billing based on estimated usage, a distributor must make available, upon request from a retailer or end-use customer, a description of the method or algorithm used for estimating usage. If a retailer or end-use customer believes that the method used produces unreasonable estimates for any period, they may ask the OEB to review the methodology. The OEB has the right to dictate a particular estimating methodology if it determines that a distributor's current approach is unfair to selected market participants.

VOTER SUMMARY:

Unanimous.

ISSUE STATEMENT: (Final?)

Global Issue Outline VIII.E.8: Calculating Customer Commodity Bills for Individual Load Transfer Customers

- How does a supplying LDC recover network and commodity costs for interval and non-interval-metered customers?
- On what basis is load-transfer customer billed and how, i.e., different total loss factors?

OPTIONS:

1. The LDC with the resident customer can extend its own distribution system to that customer and eliminate the load transfer.
2. The LDC with a customer served from an adjacent LDC's distribution system can transfer, if it so desires, its obligations to connect and supply that customer to the supplying LDC. The customer will be treated in all respects as if it had resided within the supplying LDC's territory.
3. The two adjacent LDCs are free to negotiate whatever arrangement they feel is reasonable in supplying a load transfer customer.
4. All load transfers will be treated as wholesale billing adjustments by the IMO and the required wholesale metering must be installed.

BACKGROUND INFORMATION:

RTP Report Section 3.5.3.3: Load Transfers:

Load transfers occur when a customer connected to one LDC is billed for electricity and network services by another LDC. Assume meter point F depicts a load transfer configuration where there is a meter connected to a line that might serve multiple customers billed by another LDC. Assume load E is an example where a single customer is being billed by another LDC. Loss adjustments for these situations can be calculated as follows:

$$\text{Load } E_s = (DLF_p) \times (DLF)_p \times (UFE) \times \text{Load } E$$

$$\text{Load } F_s = (DLF_p) \times (UFE) \times \text{Load } F$$

Electricity Act, 1998:

Section 28: A distributor shall connect a building to its distribution system if,

- (a) the building lies along any of the lines of the distributor's distribution system; and
- (b) the owner, occupant or other person in charge of the building requests the connection in writing.

Section 29:

A distributor shall sell electricity to every person connected to the distributors distribution system, except a person who advises the distributor in writing that the person does not wish to purchase

electricity from the distributor.

Ontario Energy Board Act, 1998:

Section 70(1 1):

The licence of a distributor shall specify the area in which the distributor is authorised to distribute electricity.

Section 70(6):

Unless it provides otherwise, a licence under this Part shall not hinder or restrict the grant of a licence to another person within the same area and the licensee shall not claim any right of exclusivity.

SUMMARY OF GROUP DISCUSSION:

Option	How does supplying LDC recover network commodity losses and costs?	How and on what basis is customer billed?	Which LDC's NSLS, distribution charges and losses would be charged to the customer?
2	Same manner of all its other customers	Same manner as all other customers in the supplying LDC	Supplying LDC
3	According to whatever agreement is reached between the two LDCs	Depending on the agreement reached, either one LDC or the other would bill the customer in the same manner it bills its other customers	The billing LDC which is identified in the agreement
4	Treated the same as other embedded wholesale customers within the supplying LDC	Customer would be billed on the same basis as all other customers within the same LDC territory as which it resides	The LDC in which the customer resides

- All interval-metered customers on a load transfer should be treated as wholesale metering points.
- Some group members were concerned that in some cases a shift from the host LDC to the supplying LDC could result in a relatively significant price increase. It was suggested that if this occurred, some form of rate stabilisation program might be called for during transition.
- Load transfer issues such as the obligation to supply, licensing areas and exclusivity are also being looked at by the Distribution Task Force. The recommendations of the two Task Forces should therefore be compatible.
- There was discussion around the option of the supplying LDC billing the host LDC for the load transfer customers in the same manner as if they were a customer of the supplying LDC (using its NSLS, losses, etc.). The host LDC would then bill the customers on the basis of its NSLS, losses, etc. and be responsible for any differences, whether positive or negative, between the two bills. This led to further complications when considering which

NSLS to use if the customer is served by a retailer. For example, should a retailer have a right to receive the lowest cost rates, whether those are from the host of serving LDC?

- It was felt that grandfathering of existing load transfer arrangements was unnecessary.
- The number of load transfer customers in the province is extremely small. Therefore a simple and expedient approach is best. This would most easily be accomplished by transferring ownership of the customers. However, it is also recognised that the issue of giving away customers has always been politically sensitive and may raise some controversy.
- Temporary supply arrangements between LDC's can still be handled using the recommended methodology. It is expected that an agreement would be entered into between the parties defining the term of the arrangement, the apportionment of costs, plus any other relevant conditions.

RECOMMENDATION:

The host LDC, which has a customer supplied by an adjacent LDC, has the choice to:

1. Install interval metering which can be used for wholesale billing adjustments. This approach would be expected if the load transfer is large enough to economically justify the expense of the metering. For existing situations, this may require the host LDC to acquire assets that the supplying LDC may have installed within the host LDC's service territory.
2. Turn the customer over to the supplying LDC such that the customer would be included within the licensed service territory of the supplying LDC and treated in the same manner as all its other customers (in the same settlement zone). For existing situations, this may require the supplying LDC to acquire assets that the original host LDC may have installed to supply the customer.

VOTER SUMMARY

Unanimous (19 Task Force members in favour).

DISSENTING OPINION

Unanimous (19 Task Force members in favour).

ISSUE STATEMENT: (Final)

Global Issue Outline VIII.E.8: Calculating Customer Commodity Bills for Unmetered Loads

- Should commodity bills for unmetered loads be calculated using the NSLS or a deemed profile?

OPTIONS:

1. Apply NSLS to all unmetered loads.
2. Allow the use of load profiles for all unmetered loads (could be a mandatory or a voluntary application).
3. Provide for a mixture of allowed load profiles and NSLS.

BACKGROUND INFORMATION:

RTP Recommendation 3-5:

Average prices used to determine bills for unmetered loads should be calculated using the NSLS rather than any independently derived load shape estimate.

SUMMARY OF GROUP DISCUSSION:

- The group generally agreed with the RTP report that the use of load profiles should not be allowed.
- However, the group also felt that streetlights were unique enough and represented a significant enough load throughout all LDCs (> 0.3 percent of total LDC load), that a special situation was warranted.
- In addition to being impractical, it is also needless to install interval metering for street lighting load due to the predictability of the load shape.
- Instead, a load profile can be rationalised by using a 'virtual' interval meter.
- Each LDC must use the "Street Lighting Load Profile" as prescribed by the OEB. It is based on (either the mid-month official Sun Rise and Sun Set times provided by Environment Canada at Toronto Airport) or (a study conducted by Ontario Hydro Services Company). *(Note: This is still being investigated.)*
- The Street Lighting Profile is to be subtracted from the NSLS.
- All other unmetered loads are not to be profiled nor subtracted from the NSLS.

RECOMMENDATION:

1. Unmetered Street Lighting Loads on public roadways are to be profiled and the load profile is to be subtracted from the NSLS. Each LDC will calculate the total installed street lighting load in kW's and then apply it to the common hourly profile presented below to determine the

street lighting load profile in their service territory. *(Note: The load profile is still being investigated.)* A utility wishing to use a different load profile must receive approval from the OEB.

Month	Time On	Time Off
January	00:00 p.m. EST	00:00 a.m. EST
February	00:00 p.m. EST	00:00 a.m. EST
March	00:00 p.m. EST	00:00 a.m. EST
April	00:00 p.m. DST	00:00 a.m. DST
May	00:00 p.m. DST	00:00 a.m. DST
June	00:00 p.m. DST	00:00 a.m. DST
July	00:00 p.m. DST	00:00 a.m. DST
August	00:00 p.m. DST	00:00 a.m. DST
September	00:00 p.m. DST	00:00 a.m. DST
October	00:00 p.m. EST	00:00 a.m. EST
November	00:00 p.m. EST	00:00 a.m. EST
December	00:00 p.m. EST	00:00 a.m. EST

- Other than Street Lighting Loads on public roadways, no other unmetered loads will be profiled. The NSLS shall be used for such loads in accordance with RTP recommendation 3-5.

IMPLEMENTATION ISSUES:

The standard load profile must still be determined.

VOTER SUMMARY:

Unanimous (18 Task Force members in favour).

DISSENTING OPINION:

None.

ISSUE STATEMENT: (Updated August 6, 1999)

This issue is being returned to the subgroup to investigate the requirements included in an appendix to the interim distribution license. These requirements appear to differ from the recommendations made below.

Global Issue Outline VIII.E.9: Calculating Customer Commodity Bills With Market Power Mitigation Rebate

- How should the market power mitigation credit (MPMC) received by LDCs be allocated to end-use customers and retailers?

OPTIONS:

1. Allocate costs to end-use customers and retailers on the basis of the number of kWhs used during the hours of the year when the wholesale price exceeded the maximum price allowed under the market power mitigation scheme. (This would require that LDCs keep hourly information for all customers for the relevant period, which might be as long as six to twelve months. It would also mean that LDCs would need to access that data and determine the cumulative usage for all periods when the spot price exceeded the allowed level for each customer—a massive data processing requirement.
2. Allocation of market power mitigation credits based on a simpler method, perhaps using each customer's share of total kWh usage or bill amount for the specified time period the MPMC relates to.
3. If dollars are small, average cost per customer basis (e.g., \$1/customer). This avoids the tasks of determining usage-based shares.

Once a methodology has been determined, it will be necessary to assess whom the credits will apply to:

1. Apply retroactively for all customers who were billed in the specified period.
2. Apply proactively for current *active* customers who had consumption in the specified time period.
3. Exclude final customers who have left the LDC service territory. (This could be complicated if customers have finalised at one location and have moved within the service territory of the LDC—how do you summarise consumption at multiple locations—if the customer is still active they will look for credits).
4. Apply to all customers currently connected to an LDC's system, whether or not they were customers during the period of time for which the credit was determined.

BACKGROUND INFORMATION:

For a period of four years after the opening of the market, 90 percent of OEGC's expected domestic energy sales will be subject to a price cap of 3.8¢/kWh on average. This OEGC price cap will facilitate Ontario customers experiencing immediate and demonstrable benefits from electricity restructuring and provide for a relatively stable average price for electricity in the province. This price cap and other electricity costs should be structured so that the blended or "all in" price of electricity would not exceed the current retail price, which averages 7.2¢/kWh.

The OEGC price cap may be subject to further change as a result of the Minister of Finance's industry financial restructuring efforts and electric power market conditions prevailing at the time of OEGC's capitalisation.

Under the price cap regime, OEGC will provide a rebate to customers when market prices would otherwise result in OEGC receiving an average price greater than 3.8¢/kWh in respect of the defined quantity of energy. OEGC would be entitled to keep all revenues from the sale of energy it produces in excess of the defined quantity. Details of the price cap regime, such as caps and weights would be public information.

It is currently unknown how market power mitigation credits will be determined by the IMO, how they will be allocated to wholesale market participants and how frequently they will be provided.

SUMMARY OF GROUP DISCUSSION:

- The difficulties of trying to keep track of customers who were connected to the system at the time that the MPMC applies were discussed at length and this option was rejected.
- It was recognised that bill amount rather than usage would be a better variable for use in allocation since the MPMC is intended to compensate users for periods when prices are higher than they would be except for the exercise of market power. Since bill amount includes the impact of pricing, it was felt to be superior to usage as an allocation factor.
- The manner in which the MPMC will be allocated to LDCs is currently unknown. The group raised questions about whether net or gross loads would be used to allocate the credit to LDCs.

RECOMMENDATION:

1. The MPMC should be allocated to end-use customers and retailers based on each market participant's share of total wholesale costs for the period covered by the MPMC provided to an LDC. In other words, each market participant's wholesale bill as calculated by the spot-price pass-through will be divided by the total wholesale costs for the relevant period. This ratio will then be multiplied by the total allocation provided to an LDC to determine the amount each market participant should receive.
2. The customer base existing at the time that the MPMC is being distributed will be used. While this may result in some windfall gains or losses for some customers, trying to keep track of customers that have left the system is impractical. For customers recently joining the system, their consumption during the relevant period should be minimal and therefore their allocation share should be small.
3. If the overall rebate is insignificant (possible suggestion for dollar cut-off as percent of total kWh cost of power purchases for the LDC), the credit should not be calculated but perhaps rolled in with other adjustments and errors.

VOTING SUMMARY:

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DISSENTING OPINIONS:

?

ISSUE STATEMENT: (Final)

Global Issue Outline VIII.E.10: Calculating Customer Commodity Bills for Standard Supply Service Customers

- Does the type and form of SSS affect retail settlement?
- If a LDC utilises an affiliate or another person to provide SSS what are the implications?
- How does the LDC provide a spot pass-through?

OPTIONS:

1. The recommendations presented below describe a step-by-step process that enables any form of SSS and spot pass through to be processed by the retail settlement methodology. Individual LDCs may use different procedures and calculations as long as they produce equivalent results.

BACKGROUND INFORMATION:

RTP Recommendation 3-1:

All LDCs in Ontario will have responsibility for determining the financial obligations of all end-use customers served directly by them (e.g., according to the default supply option or the spot-price pass-through) and for all retailers serving customers connected to their wires. LDCs must collect sufficient revenue from end-use customers and retailers to pay for all wholesale obligations billed by the IMO, except for the amount owed by direct wholesale market participants connected to an LDC's wires (who are billed directly by the IMO). LDCs must also collect revenue sufficient to cover the cost of network charges and settlement administration.

RTP Recommendation 3-2:

To fulfil the obligations identified in R3-1, each LDC must have access to information, billing and administrative systems capable of:

- Calculating electricity bills based on wholesale spot prices and measured or estimated hourly consumption for all customers.
- Calculating bills based on a smoothed spot-price option, tracking differences between these bills and bills calculated according to the spot-price pass-through and collecting "true-ups."
- Sending bills to and receiving payment from retailers when directed to do so by customers.

Fulfilment of these responsibilities may be contracted out to affiliates and third parties subject to codes of conduct or other restrictions imposed by the OEB.

A distributor can fulfil its SSS obligations through a third party or in combination with a third party, section 70(9) of OEB Act.

Market Rule 2.2.18 of Chapter 7:

The market participant responsible for satisfying the obligation to sell electricity pursuant to section 29 of the *Electricity Act*, 1998 in respect of a given distribution system shall apply for registration of that distribution system as a registered facility and shall be the registered market participant for that system.

The current draft of the SSS Code calls for a simple pass through of the spot market price. Many concerns were raised by stakeholders about the draft SSS Code. The OEB is conducting a further review of the Code and there is a possibility of changes to the current draft proposal.

SUMMARY OF GROUP DISCUSSION:

- Many utilities in the province bill residential customers on a bimonthly or quarterly basis. Any recommendation in regard to SSS or spot pass through should not force an LDC to read residential meters on a monthly basis.
- There seems to be confusion around the equal billing option associated with the currently proposed SSS. In one member's opinion, this only represents how a bill can be estimated so a customer can make equal monthly payments. The actual consumption and actual spot price must still be calculated and reconciled to the customer's payments. This could be done annually (or quarterly).
- Equal payment options for customers may have reached a maturity level, i.e., the number of customers requesting this option is no longer increasing.
- Concern was expressed by a subgroup member regarding the mechanism needed for reconciliation with a smoothed spot-price option for SSS. This would require a tracking process for spot versus smoothed which must be reconciled periodically.
- SSS customers could be interval metered, non-interval metered or unmetered.
- Market Rule 2.2.18 of chapter 7 states that if a LDC assigned the SSS to a third party that party would be the registered market participant for the distribution system and would have the IMO interface responsibility. It would follow that this party would perform the retail settlement function. This Market Rule unnecessarily constrains LDCs in regard to how they deliver SSS if they want to retain the retail settlement process. If the SSS is altered from the current proposal, for example to one where a competitive entity provided SSS, having that entity perform the retail settlement function would violate the Affiliate Code.

RECOMMENDATION:

1. The following is a step-by-step procedure that enables the SSS and spot pass-through to be processed independent of SSS design. Alternative process that can be shown to produce the same results would be acceptable.

Step 1: Perform the spot-price commodity calculation for all customers as per recommendations E.0 through E.5 or E.8 (depending upon the type of metering).

Step 2: For customers who have chosen the spot pass-through use the commodity cost from Step 1 as the basis for their bill.

For SSS customers use the commodity cost from Step 1 as the basis for settlement with the SSS provider. This could be the LDC itself or a third party. If a third party is involved, billing

the customer would depend on the arrangements with that party. If the third party performed its own billing the LDC would bill the third party on the basis of the spot pass-through price. If the LDC provided SSS itself or billed for the third party it would use approved SSS rates in the bill to the customer. If the SSS is other than the spot pass-through an accounting process is required to track the differences between the amount billed to the SSS customer and the spot-price pass-through. This would be collected from or returned to the retailer or the customer. If the LDC provides SSS the SSS Code would address how this is to be done.

2. Market Rule 2.2.18 requires clarification regarding any constraints it places on the ability of an LDC to separate fulfilment of retail settlement responsibilities from provision of SSS. If there are constraints, the subgroup recommends that the market rule be modified to provide LDCs with the flexibility to retain IMO interface and retail settlement responsibilities and to assign the SSS to a third party if it so chooses.

VOTING SUMMARY:

Unanimous (20 Task Force members in favour)

DISSENTING OPINIONS:

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ISSUE STATEMENT:

Global Issue Outline: VIII.E.11: Calculating Commodity Bills for Prepaid Metering

- How can commodity bills be determined for customers with prepaid meters in light of the fact that the load-weighted average price for kWh metered customers can only be determined retroactively, not prospectively.

OPTIONS:

1. Ban prepaid metering.
2. Ban any expansion of prepaid metering while treating existing customers using one of the three following methods.
3. Develop a special tariff for prepaid-metered customers based on a forecast of average prices for a designated period. Any differences between the forecast and actual price for a given period would be reflected in the average price for all prepaid-metered customers in the next forecast period.
4. Same as number 3 but with “true-ups” calculated for each customer and somehow collected when a customer purchases a future allotment of energy. This option assumes that the prepaid technology records consumption on a customer’s prepaid card and downloads relevant information when a customer purchases their next allotment. Not all prepaid technologies have this capability.
5. Same as number 2 but with any differences between the forecast and actual price being accrued with other settlement errors in the deferral account (defined and discussed elsewhere) and ultimately collected from all customers.

BACKGROUND INFORMATION:

The concept of prepaid metering is not new. Electricity consumption meters with coin mechanisms much like parking meters have around in other jurisdictions for more than 50 years. The modern version of this application is much more sophisticated and provides all the data acquisition requirements to satisfy typical customer information system requirements.

A typical purchase transaction of a prepaid customer consists of the customer purchasing a power card at a retail outlet. The power card value is determined by the amount of power the consumer wishes to purchase at that time (i.e., \$5, \$10 or \$50). The dollar amount of the purchase is encoded on the card’s magnetic strip and the customer takes it home. Once home, the customer swipes the card through an electronic reader that deposits the amount purchased in memory on a display unit. As power is consumed, an optical reader counts the revolutions on the consumption meter and it reduces the cash balance on the deposit accordingly.

There are currently about 3,000 customers in the province with prepaid meters. Only one LDC, Woodstock Public Utility Commission, has a significant penetration of the meters, with about 2,500 installed, representing roughly 25 percent of their total residential customer base. Through the use of prepaid meters, Woodstock PUC has reduced its year-end bad debt write-offs, from a high of \$70,000 in 1993 to a 1998 level of \$6,000. Additional benefits to LDCs include reduced billing and collection costs through staff reductions, reduced customer high bill complaints. Customers enjoy benefits of greater control over energy use which can lead to reduced consumption overall.

SUMMARY OF GROUP DISCUSSION:

Any attempt to ban prepaid metering would create stranded costs for utilities that currently have such metering installed. It would also limit customer choice, which runs counter to the intent of retail restructuring and to the business plans of selected companies.

Option 4 above would impose potentially costly minimum technology requirements on companies installing prepaid metering. The majority (perhaps all) of existing prepaid meters in the province do not have the functionality required to implement this option.

Option 5 is the simplest method to implement but it involves some cross subsidisation across prepaid and non-prepaid meter customers segments. The direction of the cross subsidy for any given period would depend on the difference between the forecast and actual cost of supply. Option 3 would eliminate this cross subsidy across these segments, but could lead to some inter-temporal cross subsidisation (e.g., future prepaid meter customers would get either higher or lower rates than previous customers depending upon the difference between the forecast and actual prices). If the population of prepaid meter customers is fairly stable, this inter-temporal cross subsidisation will be minimal.

If SSS is a fixed price offer, prepaid service would be priced at the SSS and there would not be a need to develop a special price forecast for this market segment. Settlement costs would still need to be estimated as described above.

Prepaid meters are capable of being read manually just like any other meter. The group felt that if a competitive retailer is offering prepaid meter services, the meters should be read according to normal meter reading cycles and settlement with the retailer computed as if the meter was not a prepaid meter.

RECOMMENDATIONS:

1. Prepaid meters should not be banned.
2. If SSS is a fixed price offer, prepaid meter customers should be charged the SSS price. If SSS equals the spot-price pass-through, the OEB should approve a common methodology for forecasting prices that would be used when customers purchase electricity through their prepaid cards. The methodology should include frequent (e.g., bimonthly or quarterly) updates of prices and guidelines for how prices to prepaid customers in future periods should be adjusted to reflect differences between forecast and actual prices in historic periods.
3. If a competitive retailer offers prepaid meter service, the consumer's meter should continue to be read as if it were not a prepaid meter and the retailer's settlement costs calculated in the same manner as for a normal kWh meter.

IMPLEMENTATION ISSUES:

Developing the price forecast.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: (Final)

Global Issue Outline VIII.G: Embedded Retail Generators

- What type of metering should be required for embedded retail generators?

Note: There are many other issues concerning embedded generation including whether any size restrictions should be used to distinguish embedded retail and wholesale generators, issues around VAR support and losses and what price should be used to pay generators (e.g., should it include transmission charges?). Further investigation is required to address these issues.

OPTIONS:

1. Require all embedded generators to have interval meters and do settlements according to hourly pricing.
2. Allow kWh metering and use NSLS to determine load shape of generated power and apply hourly pricing.

BACKGROUND INFORMATION:

A detent-equipped meter will only record energy in one direction. A meter not equipped with a detent will spin backwards during times of net excess generation. This may lead to negative consumption figures.

A 4-quadrant meter measures flow in and flow out for both active and reactive power. One subgroup member obtained price quotes for such meters ranging from around \$600 to \$1000. Another subgroup member thought the price could be as high as \$3,000.

SUMMARY OF GROUP DISCUSSION:

An embedded retail generator should be treated consistent with how embedded retail customers are treated.

A generator's output should be determined at the point of connection to a utility system. Treatment should vary depending on whether the generator is located on the primary or secondary side of the transformer and at what voltage level 240v, 347/600v, 4,160v, 13,800v, 27,600 or 44,000v.

Are losses to be added, subtracted or not necessary? Any transformer losses to be applied?

Do you apply NSLS to all supply from a customer with only a kWh meter?

Should all embedded generators be required to have an interval meter that records bidirectional energy?

Should generator output be priced according to supply at the nearest registered wholesale meter or grid supply point?

Are there rules that apply depending on the size of the generator and its output? Will there be technical specifications that must be met? How do you handle very small generation, solar, small hydraulic, micro turbines, etc.?

How must LDCs pay generators same as retail customers timeline?

Using the NSLS to calculate prices for embedded generators could result in a significant overpayment if, for example, a generator only provides excess power to the grid during off-peak hours. In this instance, they would receive payment that is much higher than the cost of power during the period of time when they are supplying net load to the grid.

Notes from the RTP Report, section 3.5.3.3:

Loss adjustments for embedded generation vary depending on the characteristics of the generator. For example, an embedded interval-metered generator (G_1) serving Load D, (where Load D > G_1), would have the net load adjusted in the same manner as any other load. That is,

$$Net\ Load_s = (DLF_p) \cdot (DLF_s) \cdot (UFE) \cdot (Load - G_1)$$

An embedded interval-metered generator whose supply exceeds the dedicated load (e.g., Load D < G_1) delivered at primary would be adjusted according to the following equation:

$$Net\ Supply_s = (1 - (DLF_s \cdot UFE - 1)) \cdot (G_1 - Load\ D)$$

If the generator requires Var support from the distribution network, there must also be a correction for primary Var losses according to the following equation:

$$Net\ Supply_s = (1 - (DLF_s \cdot UFE - 1)) \cdot (G_1 - Load\ D) - \\ (DLF_p - 1) \cdot UFE \cdot (G_1 - Load\ D)_{VARs}$$

Still another example with embedded generation involves a small, kWh-metered generator (G_2) and Load R. If both loads are net-metered and $G_2 < (Load\ R)$, then

$$Net\ Load_s = (DLF_p) \cdot (DLF_s) \cdot (UFE) \cdot (Load\ R - G_2)$$

If $G_2 > (Load\ R)$ and the détente is removed from a kWh electromechanical meter, the disc will reverse direction and the kWh register reading will decrease. These net-kWh meters have been used in some jurisdictions to support development of certain generation technologies. Despite the fact that, for these installations, generation is not expected to exceed load in the billing period, to require all meter-reading, settlement and billing systems to accept possible negative kWh net readings is not recommended. Therefore with a standard kWh meter, when generation exceeds load, the meter will stop and the energy delivered to the network will continue to reduce UFE.

RECOMMENDATION:

Require all embedded generators to have a four-quadrant interval meter and do settlements according to hourly pricing.

VOTING SUMMARY:

Unanimous (18 Task Force members in favour)

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: (September 29, 1999)

Global Issue Outline VIII.G.2: Embedded Retail Generation Settlement

- What are applicable charges/payments to retail generators within the LDC's service territory?
- Where is settlement point of supply for the embedded generators kWhs into the LDC's grid?
- What distribution loss factors apply to generation output of a retail-embedded generator?

BACKGROUND INFORMATION:

Per market design rules retail embedded generators are allowed to sell power into the local distribution grid at the wholesale hourly spot-price price for energy, and congestion pricing if applicable. In order to do so it has already been recommended in issue statement G.1 that the generator must have a meter with a four-quadrant pulse meter. The "grandfather generation" clause in the market design rules should also apply to retail generators.

The committee has proposed that Retail Embedded Generation and Wholesale embedded generation be priced into the market at the Primary Wholesale Revenue meter that the generator is referenced to. The metered quantities for the retail embedded generator will be adjusted by the approved DLF (distribution loss factor) for that settlement area. This will be done by metering the generator output at the Retail "secondary" location and discounting (reducing) the energy quantities injected into the LDC system by the DLF for that site

The attached table and definitions outline how retail embedded generation and displaced load by the generator should be assessed.

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Types of Retail Embedded Generators		Energy only Plus congestion from associated Grid supply point	CTC	Ancillary Uplift Other hourly or monthly commodity costs	Transmission charge	MPMC
1. Old generator displacing load at end-user site, always net consumption	Customer Charge: Generator Payment:	Net N/A	See ??	Net N/A	See transmission charges as outlined in Transmission code.	Net N/A
2a. New generator displacing load at end-user site, always net power consumer	Customer Charge: Generator Payment:	Net Retail Settlements Code Task Force—Subgroup 3—Final Recommendations N/A		Net N/A		Net N/A
2b. New generator displacing ‘new’ load at end-user site, net power consumer	Customer Charge: Generator Payment:	Net N/A		Net N/A		Net N/A
3. Old generator exporting or consuming power at their site and selling to the LDC	Customer Charge: Generator Payment:	Net Pay generator***		Net No		Net N/A
4. New generator exporting or consuming power at their site and selling to the LDC	Customer Charge: Generator Payment:	Net Pay generator***		Net No		Net N/A
5. Old generator without interval metering, exporting	Must have interval metering installed to measure power sold to LDC or power supplied to LDC will be at no for consumption at their own site without interval metering.					
6. Embedded Wholesale Generator	Customer Charge:	IMO	IMO	IMO	IMO	IMO
	Generator payment:	IMO	IMO	IMO	IMO	IMO

* Existing standby charges would still apply

** May be gross load measured if customer wants full standby from LDC or other standby charges may be negotiated for partial back

*** Generator output to the LDC grid will be at the “secondary” metering point, discounted by the DLF (losses plus UFE)

Note: Retail generators must have interval meters to sell power to the LDC.

DEFINITIONS:

1. Old generators: As defined by (Market Rules ?, Grandfather clause) Existing standby charges would continue to apply.
2. New generators: As defined by (Market Rules ?, Grandfather clause).
3. Point of supply by a retail generator to the LDC: Is the same point as the definition for the 'secondary' metering location for retail customers. The power sold to the LDC will be discounted by the DLF.
4. Site specific losses: As per distribution loss factor calculations.
5. Gross Load: All power consumed at this site as measured by the incoming power channels only of the main customer meter, plus the output of the generator measured at the generator meter. The incoming power will be adjusted to be equivalent to the secondary supply point for retail customers. There will be transformer loss adjustments for the energy measured at the generator meter to bring it to be equivalent to the customer secondary meter location.
6. Net Load: All power consumed at this site as measured by the incoming power channels only of the main customer meter.
7. Retail generator: Any generator that is connected to the LDCs distribution wires, either directly or through a customer's site or any other electrical system.
8. Main meter: The main customer meter at the secondary supply point or corrected to be equivalent to the secondary supply point.
9. Generator meter: The meter that is installed to measure the output of the generator only, i.e., does not include any customer or station service loads.
10. Exported power: Power delivered to the LDC at the secondary metering point. For gross load customers this will be the outgoing power channels of the main meter only. This power will be adjusted to be equivalent to the secondary metering point. Power exported (sold) to the LDC will be discounted by the DLF.

The power sold by a retail generator will be discounted by the DLF to treat them in the same manner as an embedded wholesale generator.

RECOMMENDATIONS:

Adopted the above table.

SUMMARY OF GROUP DISCUSSION:

?

IMPLEMENTATION ISSUES:

?

VOTER SUMMARY:

?

ISSUE STATEMENT: (Final)

Global Issue Outline IX: Retail Settlement Calculations for LDC Charges

- How should LDC costs included in the settlement bill to end-use customers and retailers?

OPTIONS:

See below.

BACKGROUND INFORMATION:

As with the other cost categories, the OEB will ultimately determine the nature of the rates and what costs will be aggregated into what categories.

Background information from the Rate Handbook and the Distribution Rates Task Force will be included in a subsequent draft. In essence, the material indicates that billing determinants for distribution charges will vary with the type of meter. Both demand and kWh-metered customers will have distribution charges broken down into fixed and variable components. For demand-metered customers, the variable components may vary with demand or both demand and energy.

SUMMARY OF GROUP DISCUSSION:

In addition to the standard distribution tariffs, LDCs must be capable of billing for specific transactions (e.g., special meter reads, customer transfer fees, etc.), retailer service fees (e.g., account set-up and/or management charges, billing service charges, etc.) and any other retail settlement costs not included in base distribution rates.

RECOMMENDATIONS:

1. LDCs must bill end-use customers and retailers according to the distribution tariffs that will be approved by the OEB.
2. At a minimum, LDCs must be capable of billing end-use customers and retailers according to the following types of billing determinants:
 1. Peak demand.
 2. Energy use.
 3. An amount that may vary by billing period and could cover any of a variety of costs including debits or credits and transaction fees.

IMPLEMENTATION ISSUES:

Determining distribution billing determinants.

VOTER SUMMARY:

Unanimous.