RETAIL SETTLEMENT CODE
TASK FORCE RECOMMENDATIONS

Report to the

Ontario Energy Board

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RICHARD CROUCH AND DON THORNE
CO-CHAIRPERSONS, RETAIL SETTLEMENT CODE DEVELOPMENT TASK FORCE

INTRODUCTION

This report presents the recommendations of the Retail Settlement Code Development Task Force concerning the retail settlement methodology and market participant obligations in Ontario's restructured electric industry. It summarises the work of a group of industry stakeholders comprised of representatives from more than a dozen electric distribution companies, the Municipal Electric Association, Ontario Hydro Services Corporation, gas distributors, providers of competitive electricity and related services, the Independent Market Operator (IMO) and wholesale electricity providers. RSTF members and their organisations are identified in Table 1.

Table 1: Retail Settlement Task Force Membership

Bacon, Bruce, Senior Consultant	Econalysis Consulting Services
Battista, Richard, Manager, Special Projects	Union Gas Limited
Bell, Kevin, Vice President, Transmission & Distribution	Great Lakes Power Limited
Clark, Al, General Manager & Secretary	Waterloo North Hydro
Druyf, Fred *(Alternate)*, Manager, Finance	Waterloo North Hydro
Crouch, Richard, Director, Retail Settlements	Ontario Hydro Services Company
Tobin, Gary, Section Head	Ontario Hydro Services Company
Bracken, Brenda	Ontario Hydro Services Company
Elliott, Laurie, Manager, Billing Services	Nepean Hydro
Gagne, Joelle *(Alternate)*	Nepean Hydro
Fallis, Jim, Director, Finance & Administration	Guelph Hydro
Forsyth, John, Account Executive	IntraLynx
Forsyth, Ray, Director of Customer Service	Sarnia Hydro Electric Commission
Frederick, Allan, Manager, Finance & Treasurer	Sault Ste Marie Public Utilities Commission
Gray, Robert, General Manager	Utilipro Canada
Hine, Greg, IMO Settlements	IMO
Fong, Clement, Section Head—Settlements, HIRS, FIS	IMO
Ireland, Norman, Secretary Treasurer/Customer Services	Simcoe Hydro-Electric Commission
Lopez, Julio, President	Enwise Solutions Inc.
McAuley, Joe, Managing Director, Business Services	Oakville Hydro
McIntyre, Jerry, Director, Utility Industry Issues	Municipal Electric Association
Tucci, Maurice *(Alternate)*	Municipal Electric Association
Murphy, Larry	Henley International Inc.
Orosz, Perry, Customer Services Supervisor	Welland Hydro-Electric Commission
Parker, Doug, General Manager & Secretary	Belleville Utilities Commission
Perdue, Richard, Vice President, Gas & Electricity	Enterprise Canada

Table 1: Retail Settlement Task Force Membership

Sadowsky, Bill, Office Manager	Campbellford/Seymour P.U.C.
Shepherd, Wayne, Vice President, Electricity Division	Enershare Technology Corporation
Spicer, John, Manager, Customer Service	Brampton Hydro
Steele, James, Director of Business Development	Brantford Hydro
Thorne, Don, General Manager & Secretary	Milton Hydro-Electric Commission
Tracey, Raymond, Customer Service Technical Supervisor	Windsor Utilities Commission
Van Overberghe, Luc, Program Officer	Measurement Canada
Villanueva, Gerry	Direct Energy Marketing Limited
Whissell, Nancy, Supervisor of Accounting	Sudbury Hydro Electric Commission
Whitney, Rod, Director of Customer Service	Ottawa Hydro
Ralph, Dan *(Alternate)*, Manager, Customer Relations	Ottawa Hydro
Zapp, Angela, Product Manager, Electricity Solutions	Schlumberger
Kuraly, Peter	Schlumberger
Zebrowski, Rick	Toronto Hydro
Tam, Ginny *(Alternate)*	Toronto Hydro

RSTF recommendations are summarised in appendices A through D. Each appendix represents the issues addressed by one of four subgroups that were organised to develop initial recommendations for consideration by the entire Task Force. The four subgroups and the corresponding appendices are:

A. Subgroup 1: Managing Customer Choice and Competitive Retailers—This set of issues primarily deals with the business rules and distributor obligations associated with implementing requests to change service suppliers and the business relationship between competitive retailers and distributors.

B. Subgroup 2: Customer and Competitive Retailer Billing and Receivables—This set of issues primarily deals with a distributor's obligations associated with different billing and settlement options.

C. Subgroup 3: Retail Settlement Calculations and Information Development—This set of issues includes incorporating IMO charges into settlement calculations, the development and application of load profiling methodologies, and development of settlement charges for competitive and non-competitive services under different metering configurations.

D. Subgroup 4: Electronic Business Transactions—This set of issues concerns the development of an electronic business transaction (EBT) process for use in communicating key, high volume information among market participants.

Each appendix is organised according to the issues that were addressed by the Task Force. For each issue, there is a summary comprised of the following information:

- Issue statement
- A list of options
- Pertinent background information
- A summary of the discussion that occurred at both the subgroup and Task Force level leading up to the recommendations that were developed.
- A list of recommendations
- A voter summary
- A brief listing of implementation issues that must be dealt with at a later date
- A description of any dissenting opinions.

It is important to note that the recommendations contained in this report and represented in the draft Code do not necessarily represent the views of each of the individual members or their organisations. They are the result of lengthy discussions, compromises and voting. While there were many unanimous recommendations, some recommendations represent the majority opinion only. In all cases where there was not unanimity, we have indicated the number of representatives who voted against the recommendation, their affiliation (e.g., retailer, distributor, etc.), what their concerns were and their preferred outcome.

Appendix E contains an annotated list of definitions that appear in section 1.2 of the Code. The appendix contains references to other codes and documents where selected definitions also appear.

PROCESS OVERVIEW

The first meeting of the RSTF was held on April 16, 1999. RSTF membership was developed from responses to a solicitation of interest circulated by Board staff in March. The solicitation was sent to all Municipal Electric Utilities in the province as well as to all parties listed on the Board's stakeholder mailing list. Interested parties were asked to submit qualifications for participants with specified skills identified in the terms of reference. All responding parties were accepted onto the Task Force.

At the initial two meetings, held April 16 and 27, the Task Force was briefed on the general issues that needed to be addressed during code development and provided with an overview of the relevant recommendations made by the Market Design Committee's Retail Technical Panel. An outline of key issues was quickly developed and the work was divided into the first three of the four subgroups identified in the introduction to this report. Subgroup membership was open to any RSTF member and the groups were formed through self-selection. Every attempt was made to schedule meetings in a manner that would accommodate participation by the same individual on multiple subgroups.

The fourth subgroup was organised much later, in August, after the Task Force realised the importance of electronic business transactions (EBT) to the workings of the market and the fact that EBT issues were important to many other issues addressed by each of the three subgroups. It was the consensus of the RSTF that an EBT system to support selected, high-volume transactions was absolutely essential to the market and that the market should not open unless such a system is in place. The recommendations of this subgroup, contained in Appendix D, provide high level, conceptual guidance to the Board regarding further development of a mandatory EBT system that is referenced in the Code.

At the early organising meetings, the Task Force discussed various approaches to addressing issues and reaching decisions. It was recognised that there would likely be occasions where unanimity was not possible. A two-thirds majority rule was agreed upon. All members also agreed that it would be important to document dissenting opinions, especially in light of the inherently conflicting perspectives that stakeholder groups were likely to hold on some issues.

A decision documentation template was developed at these early meetings containing the sections described in the introduction to this report. These decision sheets were used throughout the process to document initial background information, discussions and preliminary recommendations developed at the subgroup level. Decision sheets were circulated to the entire Task Force membership prior to Task Force meetings where they were discussed and recommendations were voted upon. Following Task Force meetings, the decision sheets were updated to reflect Task Force discussion and final recommendations. In some cases, issues were referred back to subgroups for further investigation and refinement and brought before the entire Task Force at a later meeting.

An ongoing challenge during the Task Force process was the fact that many important market design and implementation decisions that could influence the nature of the settlement process had not yet been made. Examples include the Rate Handbook, the standard supply service (SSS) decision, billing determinants that will be used by the IMO to charge for wholesale services and many more. To help address this problem, roughly mid-way through the process, the RSTF developed a set of assumptions and principles that were used to guide further development of recommendations and to evaluate recommendations that had already been made. These assumptions and guiding principles are summarised in Table 2.

Table 2: RSTF Guiding Principles and Assumptions

1. The overall objectives of the settlement code are to define the regulatory obligations of distributors to support retail competition by facilitating customer choice and accurate financial settlement among retail market participants at a reasonable cost.
2. The primary measures of success in overall market design include:
   - Low entry and exit barriers for retailers
   - Low switching costs for customers
   - Equal treatment by distributors towards all retailers
   - The absence of sustainable monopoly margins on competitive services.

   A low rate of switching among customers or limited market entry by competitors are not necessarily signs of market failure.
3. In general, distributors should not only treat all retailers equally (as required by Section 26 of the Act), they should remain neutral with respect to how they treat retailers and customers and in any disputes between retailers and customers.
4. Uniform business practices should be carefully considered where flexibility imposes high costs on retailers that operate across DISTRIBUTOR boundaries or where uniformity leads to significant scale economies for distributors. Uniformity is easier to implement when business processes and support systems are brand new. Where business processes and support systems are already well established, the cost for distributors to modify existing systems or replace them with new, uniform systems must be weighed against the cost for retailers to handle a reasonable degree of flexibility on the part of distributors.
5. Settlement system development and operating costs should be minimised, subject to the need to support customer choice through minimisation of barriers to entry and switching.
6. All reasonably incurred costs by distributors to develop and operate the settlement system should be recoverable through some combination of wires charges, user fees and transaction fees.
7. Distributors should not be subjected to undue risk in fulfilling their settlement obligations.
8. Distributors have an obligation to negotiate in good faith to offer selected optional settlement services requested by market participants. Such services should not be cross-subsidised by market participants who do not purchase or benefit from such services.
9. The settlement code should, wherever possible, provide sufficient detail and specificity to minimise the regulatory burden of implementation.
10. Having the obligation to meet the requirements of the settlement code and how those obligations are fulfilled are two separate things. The Task Force fully expects that many distributors will fulfil their settlement obligations through outsourcing or joint venture arrangements.
11. The settlement code is being drafted under a significant degree of uncertainty about other relevant obligations and market design parameters and about the level of market activity in both the short and long run. Included among these uncertainties are:

Table 2: RSTF Guiding Principles and Assumptions

- The precise nature of pricing and service information provided to distributors by the IMO
- How the aggregate cost of delivered electricity must be unbundled
- What billing determinants should be used to calculate end-use customer's and retailer's bills
- What information must be included on a customer's or retailer's bill
- The specific design for performance-based regulation of distributors
- Whether or not metering will be a competitive service
- The nature of standard supply service
- How settlement system development and operating costs should be recovered.

Many of these issues are being worked on in parallel with development of the draft code. As they are resolved, the settlement code may require modification.

Between April and October, roughly 50 subgroup and Task Force meetings were held, each running between six and eight hours. Task force members who could not attend some meetings often submitted written opinions expressing their views about preliminary decisions that were circulated prior to the meetings. As a result of this process, the recommendations presented here represent thousands of person-hours of discussion and effort by a broad cross-section of market participants.

In early October, Board staff began drafting the retail settlement code based on the detailed recommendations of the RSTF. During the drafting process, it was realised that certain recommendations were insufficiently detailed and that there were some inconsistencies or other deficiencies in the RSTF recommendations. In the interest of time, Board staff and the subgroup and Task Force leadership group developed the necessary detail or otherwise addressed the shortcomings of the recommendations, being careful to document any extensions or modifications that were made. An initial draft of the code was circulated to the entire Task Force for review and comment with the relevant extensions and modifications highlighted. Task force member comments were discussed in detail by Board staff and the Task Force leadership group and numerous modifications were made to the initial draft.

Between the initial and final draft of the code, the Board issued its decision on Standard Supply Service (SSS). As seen in Table 2, the operating assumption up until the time of this decision was that SSS for all consumers would equal a spot-price pass through of the cost of electricity in the IMO-administered wholesale market. A few modifications were made to the draft code to reflect the Board's decision that SSS for small customers will be based on a fixed-price forecast that will be constant for a year.

APPENDIX A

Subgroup 1: Managing Customer Choice and Competitive Retailers

ISSUES LIST

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ISSUE STATEMENT: ***(Final)***

Issue SG1-1: What service transactions should be included in the settlement code?

OPTIONS:

1. Include rules and procedures for all service change transactions in the Settlement Code.

2. Include only transactions that involve a retailer.

BACKGROUND INFORMATION:

Section 4.3 of the RTP Final Report states the following:

The LDC-managed customer transfer process must be capable of accommodating a variety of requests from customers and/or retailers, including:

- Customers who switch from an LDC to a retailer, with no change in metering service, but with a request for one of the following billing options:
  - Consolidated bill from a retailer.
  - Split bills (e.g., network bill from an LDC, electricity bill from a retailer).
  - Consolidated bill from an LDC (optional service).
- Customers who switch from an LDC to a retailer combined with a change to competitive metering from a retailer under any of the billing options described above.
- Customers who switch from an LDC to a retailer combined with a change to interval metering provided by the LDC under any of the above billing options.
- Customers who switch from a retailer to another retailer under any of the multiple billing and meter options described above.
- Customers who switch from a retailer to an LDC by choice.
- Customers whose contracts with retailers expire and who wish to revert to default service from an LDC.
- Customers who are dropped by a retailer for any reason and cannot receive services from another retailer, therefore defaulting to an LDC.
- Customers who are already served by a retailer through consolidated LDC billing but who want to switch to split billing or to consolidated billing by a retailer.

- Existing LDC customers who want to continue LDC service but who also want interval metering installed.

The only market transaction that does not need to be accommodated by an LDC-managed transfer process is a private financial or value-added service contract between a retailer and an end-use customer where the customer still receives a consolidated bill from an LDC (and the retailer does not ask the LDC to do billing on its behalf). Such transactions essentially involve “side deals” between customers and retailers that, by design, require no ancillary services from LDCs and, therefore, require no LDC involvement at all in the process.

RTP Recommendation 4-2 states:

All LDCs must implement changes in information systems and provide the necessary resources to facilitate record keeping and transfer procedures for all changes in electricity, meter and billing service provision except those transactions that involve only “side deal” arrangements between retailers and customers.

SUMMARY OF GROUP DISCUSSION:

Group participants felt that the Settlement Code should only address service transactions in which a competitive retailer is involved. Transactions that are purely between LDCs and customers should not be included in the Settlement Code. Such transactions should be governed, implicitly or explicitly, through the Distribution Code, the Standard Supply Code or simply “standard business practices.” Under this approach, the following transaction requests would NOT be governed by the Settlement Code:

1. A “side deal” as defined above.
2. A change in customer location within an LDC’s service territory for an SSS customer who wishes to remain an SSS customer.
3. A customer moving into the service territory who chooses SSS service.
4. A customer currently on SSS service who moves out of the service territory.
5. A change from standard to interval metering service while remaining an SSS customer.
6. A request for customer information sent directly to a customer.

RECOMMENDATIONS:

Any transaction request seeking a change in service for a customer that is currently served by a competitive retailer or for an SSS customer who wants to receive electricity supply from a competitive retailer should be governed by the Settlement Code and should adhere to the rules and procedures laid out in the Code. Specifically, the transactions included in the code are:

1. A change from SSS to competitive supply.

2. A change from one competitive retailer to another.

3. A change from a competitive retailer back to SSS.

4. A change in metering or billing options for customers currently served by a competitive retailer.

5. A change in customer location (either within the service territory or a move to another service territory) for a customer that is currently served by a competitive retailer.

6. A request to transfer customer-specific information to one or more retailers.

Any service transaction requests not included in the above list are governed by other codes or by normal business practices.

IMPLEMENTATION ISSUES:

Implementation issues for transaction requests are covered elsewhere. *(Note: This recommendation should be flagged to the DSC and SSS code groups for them to consider whether transactions not covered in the RSC should be covered in other codes or left up to normal business practices.)*

VOTER SUMMARY:

Unanimous recommendation by the Task Force.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG1-2: Which party should initiate service transaction requests?

OPTIONS:

1. All service transaction requests must be submitted by a retailer.
2. Requests can come from either a customer or retailer.
3. Requests can only come from customers.
4. Certain requests must come only from customers and others must come only from retailers.

BACKGROUND INFORMATION:

A change in any of the services covered by the Settlement Code (see the recommendations for issue SG1-1 for a list of such services) must be initiated by notifying an LDC of the desired change. Depending upon the nature of the transaction, such notification could logically come either from customers or retailers. A key consideration in deciding whether customers or retailers should initiate the request is the trade-off between customer convenience and customer protection. If notification comes directly from customers, there is little need to implement consumer protection procedures to avoid slamming (e.g., the unauthorised transfer to another retailer). However, under these circumstances, customers must be responsible for completing the necessary paperwork and interfacing with their existing retailer in order to initiate the process. If notification is provided by retailers, it is much more convenient for customers but it leaves them vulnerable to slamming.

Taking this trade-off into consideration, the RTP recommended that transfer requests should be submitted by retailers in all situations where a retailer is in a position to do so but only after obtaining written authorisation to do so. Specifically, RTP recommendation 4-3 states, in part, that:

> In all transactions involving a change to a new retailer-provided service, the change should be initiated by the retailer that will provide the new service, based on written authorisation by a customer. . . .For transactions involving a voluntary transfer from a retailer back to an LDC, or a change in service that does not involve a retailer, notification should be provided by customers.

SUMMARY OF GROUP DISCUSSION:

Subgroup participants generally favoured the submission of service transaction requests by retailers rather than customers whenever possible, based on convenience to both customers and LDCs. Once transfer procedures are established, retailers will know what they are, will have the appropriate forms or electronic interface capabilities and will be able to implement the necessary steps much more easily than customers. This approach is also much more convenient for customers for most transactions. As long as concerns about unauthorised transfers can be addressed, all group members felt that retailer-initiated transfer requests were optimal for all parties.

On the other hand, there will always be exceptions to the general rule. For example, there may very well be customers who find it more convenient to submit requests for certain types of transfers themselves. Even more likely is the fact that customers may not trust their current supplier to submit a request, for example, when a customer wants to revert to SSS service because they are unhappy with their current supplier. The group discussed the idea that, if a customer called in with a request, if a retailer is involved, the LDC should direct the customer to ask their retailer to submit the necessary information (i.e., that LDCs would not accept requests directly from customers). However, this not only seems impractical in some instances, it should logically be left up to individual LDCs to make this typical business decision.

RECOMMENDATIONS:

Although the preferred approach is to accept service transaction requests from retailers whenever possible, LDCs must be willing to accept requests from either customers or retailers.

IMPLEMENTATION ISSUES:

Details of the transaction process are discussed under issues SG1-3, SG1-4 and SG1-7 through SG1-10.

VOTER SUMMARY:

Unanimous recommendation by the Task Force.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG1-3: Nature of authorisation for service transaction request.

- What form of authorisation is required for each type of service transaction request?
- Should LDCs have flexibility with regard to the nature of authorisation they will accept?
- Who must retain records and for how long?

OPTIONS:

1. Uniform rules across all LDCs.

5. Flexibility in rules across LDCs.

6. The same form of authorisation should apply to all transaction types.

7. The form of authorisation should differ depending upon the type of transaction.

8. Retailers can retain copies of the authorisation rather than transfer originals or copies to LDCs.

9. LDCs must receive a copy of the customer's signed authorisation before proceeding.

BACKGROUND INFORMATION:

RTP Discussion and Recommendations:

The nature of authorisation for service transactions was discussed at length by the MDC and RTP. Relevant recommendations and excerpts from the RTP report, section 4, are presented below.

The RTP concluded that, in all situations, transfer requests can be implemented only upon written authorisation by a customer. The RTP debated the merits of requiring retailers to submit copies of the written authorisation directly to the relevant LDC as part of the transfer process. The RTP agreed that allowing retailers to retain the authorisation on file would be sufficient protection as long as this is an explicit obligation of a retailer licence (e.g., not obtaining authorisation would be a licence violation). However, there was concern that a literal interpretation of Bill 35, section 29(1) would appear to prohibit this approach. The relevant section states,

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

Some RTP members felt that this clause would be interpreted to require that the actual written authorisation should be in the possession of an LDC prior to implementing a transfer. If this interpretation holds up under further review, then the RTP recommended that transfer requests should still largely be initiated by retailers, rather than by customers, but that these requests must be accompanied by the written authorisation from a customer.

Given the growing importance of electronic commerce and the cost-effectiveness of telemarketing for soliciting low-volume customers, some MDC members raised concerns that the burden of obtaining written authorisation could significantly inhibit competition for small customers. Neither the RTP nor the MDC had time to investigate this issue but recommended that the issue be taken up by the OEB during the licence and code development process.

The RTP also discussed the form of authorisation required for requests to transfer customer information. A customer can request at any time that certain basic information held by LDCs be transferred either directly to the customer or to a designated retailer. Because of the potentially sensitive nature of such information, the RTP recommended that requests to LDCs for information transfer be accompanied by a copy of the actual written request form from a customer prior to providing information to a third party. The RTP recommended that this practice be adhered to even if future interpretation of Bill 35 allows transfer of supply among retailers to be based on written authorisation held in files by retailers.

RTP recommendation 4-3:

In all transactions involving a change to a new retailer-provided service, the change should be initiated by the retailer that will provide the new service, based on written authorisation by a customer. The customer authorisation document may be held by the retailer, subject to a favourable legal interpretation of Bill 35, section 29(1). If Bill 35 is interpreted to require that written authorisation be submitted directly to LDCs prior to transfer, the transfer request should still come from retailers but should be accompanied by a copy of the customer's authorisation document. For transactions involving a voluntary transfer from a retailer back to an LDC, or a change in service that does not involve a retailer, notification should be provided by customers.

RTP Recommendation 4-4:

Transfer of customer information to a retailer should only be done based upon receipt by an LDC of a copy of a written request from a customer.

OEB Staff Interpretation:

OEB staff has concluded that retailers who obtain written authorisation from a customer indicating a desire to change from SSS to competitive supply need not transmit an original or copy of such authorisation to the relevant LDC in order for the service transfer to be considered legal according to the *Electricity Act 1998*. In other words, it will be sufficient for retailers to obtain such authorisation and to keep it on file and to attest as a condition of license that such authorisation has been obtained prior to submitting a transfer request to an LDC.

The subgroup was advised by Board Staff that "written authorisation" should be defined as in the *Interpretation Act*, subsection 29(1), which states, in part, that writing, written "or any term of like import, includes words printed, painted, engraved, lithographed, photographed, or represented or reproduced by any other mode in a visible form;. . ." Based on this interpretation, electronic mail is considered a form of written authorisation but a voice recording is not.

SUMMARY OF GROUP DISCUSSION:

The subgroup agreed with the RTP recommendation that all service requests must be based on written authorisation by customers. The group also agreed with the RTP recommendation that such authorisation could be held by retailers. The group felt that retailers should attest through a positive statement on each submission to an LDC that they had obtained such authorisation from customers and that they had the records to support that contention. The group disagreed with the RTP's recommendation that requests for customer information transfers should not be honoured prior to receipt by an LDC of a copy of the customer's authorisation. In other words, information transfer requests should be subject to the same rules and procedures as any other type of request. The subgroup was also happy to accept the OEB's guidelines on what constitutes "written authorisation."

Because of the important issues of consumer protection and retailer convenience, the group felt that customer transaction request rules and procedures should be uniform across LDCs.

Regarding the issue of record keeping, the group felt that retailers should keep a copy of the customer's authorisation form at least for the duration of the contract and that LDCs should keep a record of the retailer's transaction request submission for a minimum of one year.

RECOMMENDATIONS:

1. All service transaction requests must be based on written authorisation by a customer. Written authorisation is defined as any form of authorisation for which a permanent record can be retained (subject to further legal advice on this issue).

2. Retailers need not submit to LDCs copies of the written authorisation they obtain from customers in order for a transaction to take place. Retailers are expected to retain records of such authorisation for a period of time required under the law, but in no case should the period be less than the length of the contract. When obtaining the written authorisation from a consumer to modify service arrangements, a retailer shall also obtain authorisation to act as the consumer's agent for the purpose of advising a distributor that the person wishes to obtain the service being requested. When a retailer submits a service transaction request to a distributor, the retailer shall state explicitly that written authorisation has been obtained from the consumer for both the indicated transaction and for the authority of the retailer to act as the consumer's agent in submitting the service transaction request. False claims with respect to written authorisation will be considered a violation of a retailer's license.

3. A common format for the submission of service request information and rules associated with the mode of communication of such information are yet to be developed.

4. An LDC may accept an oral request to transfer customer information, but such information will only be sent directly to a customer's billing or service address. A request to send

customer information to a retailer or to any other address will only be honoured based on rules 1 and 2 above.

5. LDCs must retain a record of communication from retailers and/or customers associated with a transaction request for a minimum of one year.

6. All of the above rules will be uniform across the province.

IMPLEMENTATION ISSUES:

Rule 3 must still be developed.

With respect to rule 5, further guidance regarding how to retain records of requests from retailers covering many accounts simultaneously.

VOTER SUMMARY:

Unanimous recommendation by the Task Force.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG1-4: Information that must be transmitted when submitting a service transaction request.

OPTIONS:

See discussion below.

BACKGROUND INFORMATION:

The RTP considered the minimum information that would be necessary to initiate and complete a customer transfer. The following list describes the information determined by the RTP to be essential for effective processing:

- Customer name and electricity service address.
- LDC customer account number. (Even if a customer is currently served and billed by a retailer, it should be mandatory that the local LDC account number is contained on the customer's bill.)
- Current retailer account number. (Since LDCs will need to keep a database cross-referencing LDC and retailer account numbers, this information is redundant with the previous requirement. However, it provides a useful cross-check on the LDC account number and also acts as a substitute for the LDC account number if it cannot be located.)
- New retailer account number, if available. (This assumes that a retailer will assign an account number prior to requesting the transfer.)
- Retailer account number with an LDC.
- Earliest date after which transfer is acceptable to a retailer and/or customer.
- A check list of the desired changes in service, including:
  - An indication of whether an entire account, which could include multiple metered supply points, is to be transferred or just a subset of the meters associated with the account. In the latter case, all meter identification numbers associated with the account must be listed and those for which supply will be changed clearly identified.
  - Whether a special meter read is desired.
  - The nature of any change in meter services (if desired, a separate form will be required to delineate the nature of the change).
  - Desired billing option (e.g., retailer consolidated billing, split bills or LDC consolidated billing, assuming the latter option is offered by an LDC).

– If an LDC is to bill on behalf of a retailer, a separate form will be required to delineate the retailer pricing option that will be accommodated by the LDC.

In addition to considering the type of information required for customer transfer, the RTP also examined the issue of information format and transmission process. Deciding whether or not there should be a mandatory format for submitting the information necessary for customer transfer requires considering the trade-off between operational convenience for both LDCs and retailers. Retailers operating across LDC boundaries will largely favour a consistent format for information transmittal, although one that allows flexibility in retailer account nomenclature (e.g., each retailer should be given discretion regarding the nomenclature used for customer account numbers). Retailers will also desire flexibility in the manner in which information is transferred. For example, many may wish to submit information electronically, perhaps using a single database containing multiple customer records. Others may wish to submit customer-specific forms using the mail.

LDCs, on the other hand, also desire flexibility in the order and format of information received. They may also want to dictate the vehicle through which information is to be delivered.

On balance, the RTP felt that uniformity provided significant advantages to retailers without placing unnecessary burden on LDCs, since this is a new process for all LDCs rather than a modification to existing, well established procedures. In other words, all LDCs will need to develop from scratch the ability to accept and process transfer request information; and therefore, it is not very burdensome to develop a common format and process. The RTP recommended that a committee of LDC and retailer representatives be organised to design a suitable form and to refine requirements for information transfer. The information should be accepted by LDCs either through the mail or via facsimile transmission. Reasonable efforts should be made by LDCs to accommodate electronic transfer of such information if desired by retailers.

Recommendation 4-6:

Each request for a change in service will, at a minimum, be accompanied by the information described above and will be submitted using a common form and/or electronic format to be developed under direction of the OEB. Information will be accepted either through the mail or via facsimile transmission. Reasonable efforts will be made by LDCs to accommodate electronic transmission of information if desired by retailers.

SUMMARY OF GROUP DISCUSSION:

The group generally agreed with the RTP list of information presented above. The proposed information is listed in the recommendation below. The necessary information falls into four primary categories:

- Information necessary to unambiguously identify the end-use customer for which a service transaction is desired.
- Information necessary to unambiguously identify the retailer who will provide the desired services.

- Information necessary to facilitate communication between LDCs, retailers and customers if questions arise.

- Information necessary to know what type of service change is being requested.

As indicated below, service address, mailing address and LDC account number are all being requested. While some questioned whether all three data elements are necessary, the primary reason for collecting all three is to allow for cross-referencing. In this manner, when processing transaction requests, if two out of three data elements match an LDC's records, the transaction can be processed without necessarily going back to the retailer. If only two data elements were provided and one was inconsistent with LDC records, the transaction would need to be delayed pending validation of the account.

Having said this, if only two out of the three elements are provided, the request will be implemented as long as the two data elements match. Originally, the group felt that processing should not proceed without inclusion of the account number. However, retailers objected to this requirement since it would preclude marketing in shopping malls or other public places where customers would not have access to their utility account number.

Another data element that is useful for service transactions is meter identification number. However, this number can be difficult to obtain. It was decided to include this on the list of optional information. However, it was not included among the items that could uniquely identify a customer in the absence of a name because the meter numbers stays at an address while customers and account numbers may move. Thus, if only service address and meter number were provided, this would not uniquely identify a customer account.

Requesting the mailing address raised some concern with a retailer on the subgroup who worried about LDCs unnecessarily contacting a retailer's customers. However, LDCs argued successfully that knowing how to contact customers is essential to satisfactory service delivery.

There was also discussion concerning the difficulty that a retailer or customer will have obtaining an account number for at least one LDC because customer's on electronic debit accounts do not receive bills. The subgroup felt that this exception to the general guidelines could be handled as long as all other information was accurately obtained.

Decisions about format and mode of communication of service requests are being tabled pending further research into the advantages and disadvantages of various electronic business transaction options. Decisions in this area must also be co-ordinated with other subgroups where information transfers are important so that a common methodology can be explored.

RECOMMENDATIONS:

1. The following information should be provided when a service transaction request is submitted:

   (a) Customer name.

(b) Service address for which the change in service is requested.

(c) An indication of whether or not the retailer will accept all accounts operating under the same name at a single address if multiple accounts are found and if the service request does not include specific account numbers.

(d) Customer mailing address.

(e) LDC account number (or numbers).

(f) Meter identification number

(g) The requesting retailer's customer-account number.

(h) The requesting retailer's registration-account number with the LDC.

(i) The earliest date after which transfer is acceptable to the retailer and/or customer.

(j) The preferred method for finalising the account (e.g., next scheduled read date, special read or last actual read if appropriate).[1] In the absence of such information, the LDC will check its retailer account set-up file to determine whether or not there is a default position regarding how to handle the final read.

(k) Identification of the desired meter services (e.g., leave existing meter, change to an interval meter, etc.) and, in the event of meter unbundling, from whom metering services will be received.

(l) Identification of the preferred billing option (e.g., consolidated billing from the retailer, split billing—if offered—consolidated billing from the LDC—if offered).

(m) Identification of any customer-specific data information desired (e.g., usage history, meter information and credit information).

2. LDCs must process requests if there is a match between any two of the three pieces of information listed in items a, b and e with the information contained in the LDCs information system (assuming no other fatal errors are contained in the service request).

IMPLEMENTATION ISSUES:

An information request form and data format will be developed once a decision has been made regarding the acceptable form of information communication.

VOTER SUMMARY:

Unanimous recommendation by the Task Force.

[1] See recommendation 3 for issue SG1-10 and the discussion for further explanation of options.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT:

Issue SG1-5:

- Allowable modes for transmitting information.
- Data format for all information being submitted.

OPTIONS:

1. Only one mode (i.e., electronic) be allowed.
2. Approved electronic messages be mandatory with balance transmitted by conventional means.
3. All modes of transmission must adhere to a standard format
4. Only approved EBT transactions must be in a standard format.
5. No rules or regulations each retailer and LDC can work out their own deal.

BACKGROUND INFORMATION:

The RTP discussed this issue and provided the following guidance:

Deciding whether or not there should be a mandatory format for submitting the information necessary for customer transfer requires considering the trade-off between operational convenience for both LDCs and retailers. Retailers operating across LDC boundaries will largely favour a consistent format for information transmittal, although one that allows flexibility in retailer account nomenclature (e.g., each retailer should be given discretion regarding the nomenclature used for customer account numbers). Retailers will also desire flexibility in the manner in which information is transferred. For example, many may wish to submit information electronically, perhaps using a single database containing multiple customer records. Others may wish to submit customer-specific forms using the mail. LDCs, on the other hand, also desire flexibility in the order and format of information received. They may also want to dictate the vehicle through which information is to be delivered.

On balance, the RTP felt that uniformity provided significant advantages to retailers without placing unnecessary burden on LDCs, since this is a new process for all LDCs rather than a modification to existing, well established procedures. In other words, all LDCs will need to develop from scratch the ability to accept and process transfer request information; and, therefore, it is not very burdensome to develop a common format and process. The RTP recommends that a committee of LDC and retailer representatives be organised to design a suitable form and to refine requirements for information transfer. The information will be accepted by LDCs either through the mail or via facsimile transmission. Reasonable efforts will be made by LDCs to accommodate electronic transfer of such information if desired by retailers.

Recommendation 4-6:

Each request for a change in service will, at a minimum, be accompanied by the information described above and will be submitted using a common form and/or electronic format to be developed under direction of the OEB. Information will be accepted either through the mail or via facsimile transmission. Reasonable efforts will be made by LDCs to accommodate electronic transmission of information if desired by retailers.

SUMMARY OF GROUP DISCUSSION:

It was decided that this need not be a separate code item but could be accomplished by enhancing the recommendation of subgroup 4 to include formatting of non mandatory messages. The medium of transmitting the message would be left to the retailer and the LDC to work out.

RECOMMENDATIONS:

It was concluded that the issue was already being handled by subgroup 4.

IMPLEMENTATION ISSUES:

The EBT system and the templates for the future transactions need to be developed.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT:

Issue SG1-6:

- What information must be stored by an LDC and for how long?
- What information must be stored by a retailer and for how long?

OPTIONS:

1. Rely on the municipal, provincial, federal or accounting bodies to provide guidelines.
2. Specify minimum retention of information to help resolve disputes.

BACKGROUND INFORMATION:

This issue was not defined in the RTP volume 4. All governments and accounting bodies set out schedules for the retention of documents.

SUMMARY OF GROUP DISCUSSION:

Discussion centred around whether this needed to be written in the code or should we rely on other regulations and business practices to determine the retention process. We determined that the length the documents were kept could be left to other regulations and processes but we should provide the minimum in terms of what is kept.

RECOMMENDATIONS:

Each LDC is expected to meet federal, provincial and municipal legislation, accounting or other business processes concerning retention of records. New items have been identified in this code as business transactions and should be added to the list of items to be retained.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

All members voted in favour except one.

DISSENTING OPINIONS:

One member felt that information should be returned to allow the NSLS to be recalculated if necessary.

ISSUE STATEMENT: ***(Final)***

Issue SG1-7:

- Allowable frequency of customer switching and information request.
- Procedures to determine whether service requests should be processed.

OPTIONS:

1. Limit the number of customer transfer requests that will be honoured over a specified period of time.
2. No limitations, as long as costs are covered.
3. Process all service transaction requests without regard to current contractual arrangements and with no waiting period.
4. Process all service transaction requests after sufficient time and notification to allow current retailers to contact customers and apprise them of their current contractual obligations.
5. Only process requests when the current retailer indicates that there are not contractual impediments to switching.

BACKGROUND INFORMATION:

The allowable frequency of customer switching and the procedures for screening whether or not a change in service should be allowed are closely related issues. If the number of transfers are limited, for whatever reasons, this fact must be part of the screening process. Conversely, screening procedures that determine whether or not a change should be allowed may limit the frequency of switching.

A fundamental issue that must be considered is whether the transfer screening process should be designed to help maintain the sanctity of retailer contracts by refusing to make transfers if there is an existing contract or, alternatively, should simply process all requests that are received, implicitly relying on other factors to provide such protection. An alternative approach would be to notify existing retailers of an impending change and allow sufficient time for them to contact their customers and apprise them of their current contractual obligations. In this latter case, if the customer insisted on changing even in the face of potential legal ramifications, the transfer would be processed.

A closely related issue is whether the characteristics of SSS service require similar protection. For example, if SSS is a fixed-price offer backed by bilateral contracts, it may be necessary to limit the number of customer transfers, perhaps only allowing transfers to occur once a year. If SSS is simply a pass through of the wholesale spot price, no such protection would be necessary.

After extensive discussions, the RTP/MDC agreed to recommend that a process be implemented that would protect the sanctity of retailer contracts with customers. The following excerpts from the RTP report, and the accompanying recommendation, explain the recommended process.

Determining whether a customer should be allowed to change retailers can be done one of three ways:

- One approach is to have competing retailers solicit information from customers about their existing contract terms in order to determine whether they are eligible to switch suppliers. If a transfer is made when current contract terms don't allow it, the original retailer can contact the consumer and/or retailer and explain the error and then submit another transfer request to put things back in order. This process implicitly places the burden of knowing what the terms of existing contracts are on customers or retailers soliciting their business. It also limits the administrative burden on LDCs and avoids any potential involvement by LDCs in customer and retailer disputes. However, if most small customers don't know their contract terms, this approach could result in significant confusion for customers and significant additional cost for retailers.

- Having LDCs notify existing retailers prior to authorising a transfer to determine whether the terms of the current contract with a customer who is trying to switch retailers allows the customer to do so at the desired time.

- A third approach is to maintain a database on the terms of existing contracts that can be queried each time a transfer is requested in order to determine whether a customer is free to switch. This approach has two shortcomings. The first is that it requires LDCs to maintain a much larger and complex database and to implement a more detailed search prior to authorisation. A second problem is that it requires all competitive retailers to submit detailed information on contracts to LDCs, which they may be reluctant to do. This approach is effective in the gas industry because the market structure requires LDCs to already have information about contract duration. This is not the case in the electricity industry.

After careful consideration of the above options, the RTP rejected the third option for the reasons identified above. Initially, the RTP favoured Option 1 because of its limited burden on LDCs. However, retailers on the RTP felt strongly that this approach could be extremely cumbersome and disruptive for both customers and retailers. It could also significantly erode already thin margins as retailers could often be required to pay transfer charges twice (or even more often) for the same customer.

As a result of these legitimate concerns, the RTP changed its original recommendation to one that requires LDCs to notify retailers currently serving customers when a new transfer request is received and to wait for ten working days before implementing the transfer (unless a customer is currently being served under the default supply option, in which case transfer can occur as soon as practical). If the current retailer does not lodge a protest during that ten-day period, the transfer will proceed. If a protest is received, an LDC will place the transfer on hold until the dispute is resolved and further notice is received from one or more of the relevant parties indicating resolution of the matter. Until the matter is resolved, the current retailer is obliged to continue serving the customer and is responsible for payment of all relevant charges to the LDC according to the original arrangement. If the LDC is contacted by the customer during this period, the LDC will inform the customer of the dispute and provide the customer with contact information for each retailer and for the relevant dispute resolution organisation. The LDC must maintain a neutral stance vis-à-vis all parties.

Recommendation 4-7:

LDCs should be required to notify retailers currently providing service to a customer of an impending change in service prior to making the change and to wait ten working days before implementing the transfer. If during that period a current retailer indicates that existing contract terms prevent a transfer, an LDC must cease transfer processing until the matter has been resolved and proof of the resolution has been submitted with further instructions regarding whether and how to proceed. LDCs must maintain neutrality with respect to all parties during this process. Until the matter has been resolved, the current retailer will continue to serve the customer and pay the LDC according to the existing contract terms and arrangements.

SUMMARY OF GROUP DISCUSSION:

This issue was discussed at length over several meetings. The subgroup dealing with this issue initially favoured the RTP recommendation which would cease transfer processing if a customer was currently being served by a supplier with a valid contract and the current retailer notified the LDC that a transfer should not occur. An initial vote at the Task Force level approved the subgroup recommendation although a number of LDCs were concerned about preventing customers from switching suppliers. Some LDC representatives felt that there could be legitimate reasons for switching even if a contract exists (e.g., inferior service, lack of understanding of price offers or contract terms). Others simply didn't want to have responsibility for policing contracts, feeling that that was the job of retailers and the courts. However, on the advice of retailers that the RTP recommendation was necessary in order to encourage market entry, the Task Force approved the subgroup recommendation.

The issue was reconsidered in light of advice from Board staff that the Board would likely interpret this recommendation as going against the right of customers to choose their electricity supplier, which is one of the *Act's* primary goals and the most important responsibility of the Board. Board staff advised the Task Force that electricity supply and delivery are separate businesses and that LDCs should not be allowed to use control of the delivery business to deny customers access to supply. In the opinion of Board staff, customer mobility is fundamental to a successful market. The Board has made its opinion clear on this issue in recent decisions in the gas industry and there is little reason to believe that their opinions will differ in electricity. Furthermore, Board staff feels that it is inappropriate to design a market around the belief that customers will break contracts. In the opinion of Board staff, most customers will not, without just cause, knowingly break a contract and if they do, the appropriate remedy is through the courts, not through a refusal by LDCs to transfer a customer to another supplier upon request.

After rebuttal by retailer representatives and further discussion, the Task Force voted in favour of the recommendations presented below, which allow customers to transfer over the protests of current retailers but only after sufficient notice and time for retailers to contact customers apprising them of their contractual obligations and the potential legal consequences of changing suppliers prior to contract termination.

Concerning other issues, the group saw no need to limit the frequency of customer switching as long as the transaction cost of all transfers was covered either by customers or retailers. As mentioned above, this recommendation might need to change if SSS is a fixed-price service since an LDC's supply contract might have "take-or-pay" provisions or some other constraints necessitating limitations on customer churn.

Other factors that should be considered when screening service transaction requests are whether or not prudential requirements need to change and, in the case of information transfers, whether or not the limit of two requests per year has been exceeded.

RECOMMENDATIONS:

1. When a request is received to transfer a customer to a new retailer or to SSS, an LDC must check its records to determine whether the end-use customer is currently served by a competitive retailer or whether a transfer request from another retailer is currently pending. If neither of the above conditions exist, the request should be processed. If a customer is currently served by another retailer or another retailer's request has already been received by an LDC, the LDC must notify the current retailer that a request for a change in supplier has been received and will be processed within ten business days unless the current retailer notifies the LDC that a contract currently exists and requests an additional ten-business day waiting period. If no reply is received within the designated time period, the request should be processed. If the LDC is notified to wait an additional ten-day period, the LDC must send a notice to the retailer or customer who submitted the original request indicating that a contract with another retailer currently exists and that the transfer will be delayed to allow the current supplier to contact the customer and discuss the situation. If the LDC receives no further word from any party within the additional ten-day period, the transfer will be processed. If notice of withdrawal of the transfer request is received from any party (e.g., the current retailer, the new retailer or the customer), transfer processing will cease

2. Assuming that SSS is the spot-price pass through, that there are no contractual limitations prohibiting switching and that all transaction costs are covered, there should be no limitation on the number of times a customer may switch suppliers.

3. LDCs may also cease processing transfer requests if a retailer has not updated his or her security arrangements after notification by an LDC that such a change is required and after the 20-business-day period has elapsed. (See recommendations for issue SG1-13 for further explanation of prudential updating requirements.)

Note: Rules associated with requests for historical customer information are discussed in the write-up of that issue.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Twelve in favour, including the one participant representing a wholesale electricity supplier; four opposed, including the three retailer representatives and one LDC; four abstentions

DISSENTING OPINIONS:

Those opposed to the recommendation favoured termination of a transfer to a new retailer if a supply contract currently exists and the current retailer objects to the transfer.

ISSUE STATEMENT: ***(Final)***

Issue SG1-8: Rules to follow if multiple requests are received by an LDC.

OPTIONS:

1. Process all requests in the order received, recognising that time lags could lead to the implementation of multiple requests.

2. Develop a preliminary screening process that determines whether a previous request has been received but not yet processed.

BACKGROUND DISCUSSIONS:

RTP recommendation 4-9:

LDCs should process customer transfer requests in the order they are received. If two or more requests are received before a transfer has been processed, only the first request will be honoured and notice will be provided by LDCs to retailers whose requests will not be processed. . . .

SUMMARY OF GROUP DISCUSSION:

The subgroup agreed that requests should be processed in the order received and in the same manner as any request. All incoming requests should be date and time stamped. When a request is received, information must immediately be input to a database that a request is pending. In this manner, if a second request is received prior to completion of processing of the first request, the normal procedure of notification to an existing retailer that a transfer request was received can be used, except in this case the existing retailer is pending rather than complete. The group felt that it would be unfair to cease processing of the first request while things were being worked out because it might cause the pending retailer to miss a transfer date coinciding with the next normal read date.

RECOMMENDATIONS:

LDCs should process customer transfer requests in the order they are received. Transfer requests should be date and time-stamped at the time of receipt. Information that a request is in process must be entered into a database at the time of receipt. If a second request is received while the first is pending, an LDC must notify the pending retailer that a second request has been received and that the second request will be processed unless the pending retailer notifies the LDC within ten business days. If no notification is received, the second request will be processed. If notification is received within the ten-business-day period, both transfer requests will be placed on hold for an additional ten business days and the second retailer and customer will be notified. If a withdrawal of either request is received from any party (e.g., the pending retailer, the second retailer or the customer), the other request will be processed. If no further communication is received, the second request will be processed.

IMPLEMENTATION ISSUES:

LDCs will need to develop a date stamping and screening process.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT:

Issue SG1-9: Allowable timeline for transactions and interactions.

OPTIONS:

1. The minimum time frame for the validation and completion of requests from the Customer or the retailer should be uniform throughout the province.

2. The minimum time frame for completing requests can vary depending on the size of the LDC.

3. Allow LDC business practice to set out time frame.

BACKGROUND INFORMATION:

Retailers should expect transactions to be completed within a certain time frame for all LDCs, regardless of their size.

The PBR requirements set out service standards for connection of new services and written response to inquiries as being ten working days.

SUMMARY OF GROUP DISCUSSION:

Two areas were identified as requiring some time lines: (a) The validation period, i.e., the period during which the LDC validates the request as meeting requirements and agrees on the switch date; and (b) the notification period or the time frame from when all conditions have been met and the information is available to the retailer. The EBT system would most likely inform the retailer when a request has been received. However, nothing would prevent the request from sitting on a desk for a period of time before action is taken. We felt that action should be taken on the request within a defined period. Five and ten business days were discussed and it was felt that five business days were reasonable for the validation period to be completed. After great discussion it was determined that the retailer didn't need formal notification that a switch had taken place but would relay on the initial information from the LDC of the switch date. Should the switch not take place on that date the retailer should be informed.

RECOMMENDATIONS:

Request for customer information by a customer or retailer must meet the timelines as set out in the PBR Rates Handbook (currently ten business days)

1. The LDC must complete the validation of a request to switch within five business days of the receipt of the request. The LDC will inform the retailer that the requirements have been met and the date upon which the switch will occur or return the request with the reasons. The retailer must be notified If a switch date cannot be met by the LDC.

2. Request for customer usage history and/or payment history must be completed within ten business days from date all requirements are met.

3. Requests for a meter change must be completed on the requested date. The minimum required notice for meter changes is ten business days.

4. Retailer registration with an LDC must be effective five business days from the date all requirements are met.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG1-10: Rules and procedures for determining settlement obligations at time of a change in supplier.

- Can transfers among suppliers be made based on estimated meter reads or must transfers coincide with actual reads?
- If transfers must be based only on final reads, what options should customers/retailers have with respect to transfer timing?
- What obligations do LDCs have with respect to notifying retailers regarding the timing of actual transfers?

OPTIONS:

1. Transfers based on estimated reads by LDCs
2. Transfers based on customer card or phone-in reads
3. Transfers based only on actual meter reads
   (a) Transfers coincide with next scheduled read date
   (b) Transfers based on special reads
   (c) Transfers coincide with last actual read date
   (d) Any of the above at the request of retailers and/or customers.
4. If transfers are based on the next scheduled read, must LDCs notify retailers regarding when the transfer will occur?

BACKGROUND INFORMATION:

The options considered and recommendations made by the RTP are described in the following paragraphs.

When a customer changes to an alternative electricity supplier, financial settlement must be completed among all parties as of the relevant transfer date. Since it is highly unlikely, except by design, that a transfer date will coincide with a normal meter read date, a decision must be made regarding what information should be used to determine final bills for all parties. There are at least six options to consider:

- Require a special meter read.
- Have transfer occur on the date of the next normal meter read.

- Allow transfer to occur at any time but have final bills calculated later based on the next normal meter read.

- Allow transfer to occur at any time based on estimated usage information with a later adjustment based on actual usage following the next normal meter read.

- Allow transfer to occur at any time based on estimated usage information with no adjustment.

- Allow transfer to occur based on phone-in or card reads by customers.

There are advantages and disadvantages to each approach. Option 1 allows transfer to occur at any time and allows LDCs to calculate final bills at the time of transfer. However, it imposes costs on customers associated with special reads and, thus, may inhibit switching for small customers.

Option 2 avoids the cost of special reads but could delay transfer by 30 to 60 days based on monthly and bimonthly read cycles (the latter being the most common in Ontario) and even longer for the quarterly read cycles common among small customers in Ontario Hydro Servco's territory. For seasonal customers who may have their meter read only once or twice a year, the delay would be extremely long.

Option 3 allows transfers to occur at any time and only delays the calculation and issuing of final bills based on read cycles. The primary disadvantage is that it requires allocation of usage to the periods before and after transfer. This is an inherently adversarial process since under allocation of usage to one party automatically means the other party pays more than is equitable.

In addition to the same disadvantage as option 3, option 4 requires issuing two final bills rather than only one (e.g., estimated and final bills).

The obvious disadvantage of option 5 is that final bills could be quite inaccurate if actual consumption for the billing period is significantly different than the estimated amount.

Option 6 is similar to option 5 but phone-in or card reads are likely to more accurate as long as customers are honest. Transfers are allowed based on phone-in reads in Britain. Britain also allows transfers to be made based on estimates as long as parties agree.

In New Jersey, transfers are made according to a normal read cycle (meters are read monthly in New Jersey), but if a read is missed, a transfer is still made based on an estimate.

Taking these advantages and disadvantages into consideration, the RTP recommended that transfers coincide with final meter reads. Customers/retailers should be given the choice of having such transfers coincide with the next normal meter read, in which case there would be no incremental meter reading costs associated with the transfer or have a special meter read done and paid for by the requesting party.

An important ancillary issue concerns whether or not retailers should receive notice from LDCs concerning when the transfer date will be. In other words, if a retailer requests that a transfer occur on the next normal meter read date, should LDCs be required to send a notice to the retailer indicating when that date is? In the interest of minimising burden on LDCs, the RTP initially recommended that this not be a mandatory service provided by LDCs. Some RTP members argued that retailers should be able to find this information out from a customer's bill at the time of sale since bills indicate when the last read date was. However, retailers strongly objected to this recommendation, indicating that they must know with reasonable precision when they will take over responsibility for customers and that customer's bills are not always readily available. The MDC did not reach a substantial consensus regarding what to recommend on this issue so it is left up to the OEB to decide how best to proceed.

RTP recommendation 4-8:

Customer transfers must coincide with a meter reading. Customers/retailers may have transfers occur at the time of the next normal meter read or request and pay for a special meter read on a designated date. The OEB must decide whether or not LDCs should be required to send a notice to retailers indicating when the next normal meter read, and therefore customer transfer, will occur.

SUMMARY OF GROUP DISCUSSION:

The subgroup was initially unanimously in favour of only allowing transfers to occur based on actual meter reads coinciding with the transfer date. An actual read is defined as a physical read by an LDC or licensed MDMA representative (including remote reads). Customer card reads or phone-in reads are not considered actual reads. However, one Task Force participant suggested that if all parties agreed to have transfers based on a card read or even an estimate, this should be allowed. Most participants agreed that a "consenting adults" clause made sense, although there were differences of opinion regarding which "adults" needed to be included in the decision. For example, if a transfer occurs from one retailer to another, and the two retailers agree on an estimated amount on which to finalise one account and start the other, must the customer's permission be sought as well? An additional complication is that the Measurement Canada representative on the Task Force had concerns about finalising bills based on estimated reads. Ultimately, the Task Force agreed to include the "consenting adults" clause in recommendation 1 below, but this may need to be modified depending upon the outcome of further review by Measurement Canada.

The subgroup was unanimous in recommending that there be a choice regarding whether to transfer a customer based on a special meter read paid for by the requesting retailer or customer or based on the next normal meter read, in which case there would be no incremental charge for meter reading. (There would still be a transfer charge to compensate for processing the service transaction request.) After much discussion, the group also found it acceptable to transfer customers based on the most recent actual, historical meter read date under the following two circumstances:

1. SSS equals the spot price pass through.

2. An LDC has not issued an estimated bill since the last actual read date.

Under these circumstances, a retailer/customer who elects this option would agree to take over supply as of the last actual read date. Given the above two circumstances, there would be no difference in the settlement calculation for the next billing period between the SSS option and settlement for the retailer, and there would be no need to recalculate the estimated bill for a previous period or to issue a new out-of-cycle bill.

The group discussed at length rules and procedures associated with difficult to read meters and missed meter reads. The group acknowledged a utility's right to read a meter and the obligation of customers to provide access. On the other hand, the combination of indoor meters and dual-working households often makes it difficult to obtain access to meters and may require persistence in scheduling and following through with special meter read appointments. The group also acknowledged that retailers should be able to expect to have customers transferred within a reasonable time frame without incurring the cost of special reads. In attempting to balance the practical difficulties associated with certain meter reads against the needs of retailers, the group came up with the following recommendations:

1. Customers/retailers who request transfers based on the next scheduled read should be able to expect that the read will actually be made. If it is missed, for whatever reason, the cost of a special read will be borne by the LDC if it can be done during normal business hours and is not prohibitively expensive (e.g., helicopter or snowshoe reads on remote islands).

2. If the special read is also unsuccessful, the LDC and retailer must negotiate how to proceed.

3. If a retailer requests and pays for a special read and that read is unsuccessful, an LDC has an obligation to obtain the read at no additional cost and to keep the retailer appraised of any difficulties, delays and actions they are taking to address the problem as long as it is reasonable to expect that the read will be successful.

Concerning the issue of notification of retailers by LDCs regarding when transfers would occur, the subgroup discussed several approaches to this issue. The hope and desire of LDCs is that they can, in most instances, avoid notifying retailers regarding the transfer dates of each customer by establishing a set of rules, unique to each retailer, regarding when transfers would occur. For example, for LDCs that read monthly, a rule might be established to transfer all customers on the next read date after receipt of the transfer request (and after the ten-day waiting period following notification of any current suppliers) as long as the read date occurs within 15 working days. If the read date is further in the future than 15 working days, transfer would occur on the last read date (assuming that the transfer is from SSS as defined above). If neither of these criteria are met, the LDC would notify the retailer as such and seek input on whether or not to implement a special read.

The above set of rules probably wouldn't work well for an LDC with quarterly meter reading, since there would be too much uncertainty about the actual start date. In this instance, a retailer might request an LDC to supply it with the next scheduled read date and the last actual read date and then reply on a customer-by-customer basis with instructions on which option is desired. There was general agreement that LDCs must be prepared to notify retailers regarding when read dates are scheduled and when the last occurred and implement one of the three options that are available (e.g., next read, special read and, in certain circumstances, previous actual read) based on retailer instructions. However, there is also the expectation, at least for LDCs with reasonably short meter-read cycles and high completion rates, that they will be able to automate much of the process through up-front negotiations with retailers.

RECOMMENDATIONS:

1. All changes in supply arrangements should coincide with an actual meter read so that final bills and initial bills can be accurately determined. An actual read is defined as a physical or remote read performed by an LDC or licensed MDMA. Customer card or phone-in reads are not construed to be actual reads. However, if all relevant parties who might be negatively affected by the process agree in writing to allow a transfer based on a phone-in or card read or even an estimate, this will be allowed.

2. In all circumstances, LDCs must offer retailers and/or customers the choice of having the final read, and therefore the transfer date, coincide with a scheduled meter read date or be based on a special read. In the latter instance, the retailer and/or customer who requested the special read will be charged for it based on costs prudently incurred. If the costs are expected to significantly exceed the special read cost for the average customer on an LDC's system, the LDC must let a retailer know what the cost will be before undertaking the special read. This requirement is intended to help ensure that very high-cost special reads (e.g., helicopter reads on remote islands, snowshoe reads, etc.) are not undertaken without prior knowledge and authorisation of the party who will pay for the costs.

3. Assuming that SSS is a spot-price pass through, LDCs must also offer retailers/customers the choice of having a transfer from SSS to competitive supply or from competitive supply to SSS coincide with the last actual meter read date as long as an estimated bill has not already been issued subsequent to that read date. Transfers from one competitive retailer to another may also be done based on historical meter readings as long as an estimated bill has not been issued and as long as both retailers agree on the common transfer date.

4. In the event that a retailer has requested that a transfer coincide with the next normal meter read, and that the meter read does not occur, an LDC must implement a special read within five business days following the missed read date at no charge to the retailer or consumer for a read attempt during normal business hours. However, if past read records indicate that success is unlikely, an LDC can negotiate immediately with a retailer regarding how best to proceed without incurring the additional expense of a special read that will almost certainly be unsuccessful. If a special read is attempted but is unsuccessful, the LDC must immediately notify the retailer and/or customer, explain the reasons why the meter read was unsuccessful and negotiate a plan of action.

5. In the event that a retailer or customer has requested and paid for a special read in order to have a transfer date outside of the normal meter read cycle and that special read is unsuccessful, an LDC must immediately notify the retailer of the failed attempt and negotiate a plan. If a transfer ultimately fails to occur for lack of a meter reading, the retailer should not have to pay for the special reads that were attempted but failed.

6. If a retailer and/or customer requests a transfer coinciding with the next normal meter read, an LDC must either notify the retailer and/or customer about the date of the next scheduled meter read or must negotiate with the retailer ahead of time regarding what rules to follow for implementing transfer options.

IMPLEMENTATION ISSUES:

The nature and format of information exchange for the above transactions must be developed.

VOTER SUMMARY:

Unanimous vote for recommendations 2 through 6; two dissenting opinions regarding recommendation 1.

DISSENTING OPINIONS:

Two Task Force participants registered dissenting opinions on recommendation 1, favouring instead that estimated or card reads not be allowed at all. As indicated above, Measurement Canada is looking into the legality of the recommendation.

ISSUE STATEMENT: ***(Final)***

Issue SG1-11: What customer-specific information must be made available upon request by a customer or retailer?

- How frequently must the data be made available?
- Should there be a standard format that all LDCs must adhere to when providing customer-specific information?
- What mode of communication should be used to distribute customer-specific information?

OPTIONS:

LDCs hold a wide variety of customer-specific information, some or all of which could be made available. The group considered all relevant information on a case-by-case basis.

With regard to frequency, the most relevant options include:

1. Customer-specific information should not have to be released at all.
2. As often as anyone wishes as long as they pay for all transactions.
3. A certain number of information releases at no direct cost, with additional releases for a charge.
4. Unlimited access at no direct cost.

BACKGROUND INFORMATION:

MDC recommendation 4-27 from the Second Interim Report (as modified in final report):

We recommend that upon written request by a customer, the IMO and LDCs must make available to the customer and to customer-designated competitive providers of electricity, metering services or other electricity-related services the following data: customer name, service and billing address and, if available, telephone number; 24 months of historical metered usage, demand data and any other billing determinants including read dates; the tariff designation under which the customer is served; the meter type; and credit information. The data should be provided in a common format to be approved by the OEB. These parties are under no obligation to provide any data other than those listed here.

The only change between the recommendation quoted above and the original recommendation provided in the Second Interim report is that the original recommendation placed this obligation not only on the IMO and LDCs but also on retailers. After much discussion at the MDC, the obligation on retailers was dropped for several reasons, including:

- LDCs essentially have all of the relevant information anyway and for a longer period of time than retailer's might have it;
- If retailer's were obligated to provide such information for an extended period of time, detailed rules would be required to ensure that information is transferred to new retailers when contracts terminate;
- This would impose unnecessary costs on retailers.

MDC recommendation 4-28, Second Interim Report:

We recommend that no charge may be levied for the provision of data requested under recommendation 4-27 for the first two requests by a customer in any calendar year. LDCs and the IMO may levy a charge for additional request, subject to approval by the OEB while competitive retailers may levy a charge which may be reviewed by the OEB and revised if it is found to be unreasonable.

We note that the reference to retailers in recommendation 4-28 is not relevant in light of the fourth quarter changes to recommendation 4-27.

Recommendation 7-1:

The RTP recommends that information required for billing and operations be provided only to entities involved in supplying electricity to customers and be used only for the purpose for which it is provided. Restrictions on the use of this information must be clearly stated in supply tariffs or contracts. This recommendation and recommendations 7-2 through 7-15 apply to customer-specific information that is made available through provision of energy services to customers—information that is made available on a nonvoluntary basis.

Recommendation 7-2:

The RTP recommends that the OEB define basic information. Designated information custodians should be required to provide whatever historical basic information is readily assembled electronically upon a customer's request. The OEB should set minimum requirements concerning the historic period that custodians are required to maintain.

Recommendation 7-3:

The RTP recommends that customers have the choice of transferring their payment history along with basic information as defined by the OEB. If customers do wish to transfer their payment history, they must indicate explicitly (e.g., by checking a box) that they wish to do so. If no indication is provided by a customer, all basic information except for payment history will be transferred upon a customer's request.

Recommendation 7-4:

The RTP recommends that consumers always have the right to access their basic information.

Recommendation 7-5:

The RTP recommends that no entity be able to use basic consumer information for secondary purposes unless the consumer explicitly agrees in writing to such use.

Recommendation 7-6:

The RTP recommends that basic information, as defined above, be transferred upon a customer's request at no charge at least twice a year. Additional transfers beyond the first two must be performed for a reasonable charge.

Recommendation 7-7:

The RTP recommends that the OEB define the period of time in which basic information must be transferred to the entity designated by a customer.

Recommendation 7-8:

The RTP recommends that, following a customer's request, information custodians provide non-discriminatory access to basic customer information.

Recommendation 7-9:

The RTP recommends that the information custodian with additional customer-specific information be required to transfer this information upon customer request, if possible, at a reasonable cost and within a reasonable period of time. Additional information must be provided on an equal basis (i.e., in the same amount of time and for the same reasonable charge) regardless of the entity to whom the information is to be transferred.

Recommendation 7-10:

The RTP recommends that customers be informed about the conditions under which information may be transferred to third parties without their consent, including law enforcement requirements, past due accounts and aggregated consumer data.

Recommendation 7-12:

The RTP recommends that distributors maintain basic information. In the case of additional information, the customer's distributor or the IMO must transfer the information, if available, upon request by a customer.

Recommendation 7-13:

The RTP recommends that distributors recover costs incurred for the maintenance of basic information through the distribution tariff. Incremental costs of transferring information should be recovered through a regulated information transfer charge paid by the customer requesting the transfer.

Recommendation 7-14:

The RTP recommends that IMO or distributor in possession of customer-specific information beyond basic information be required to provide this additional information upon customer request for a reasonable fee.

Recommendation 7-15:

The RTP recommends that the OEB create a standard format for transfer of basic information. The standard format would include space for all basic information items and payment history.

In brief, the above recommendations:

- Designate LDCs as the sole custodians of customer-specific information.

- Give customers the right to control provision of and access to customer-specific information.

- Distinguishes between basic information that is essential for the working of the market and, therefore, should be maintained and provided upon request and "additional" information that LDCs may have on customers. The recommendation directs the OEB to precisely define each information type. The recommendations also say that LDCs should make any customer-specific "additional" information available upon request.

- Suggests that basic information should be made available twice a year for free and additional times at reasonable cost.

- Indicates that a standard format should be used for information transfers.

SUMMARY OF GROUP DISCUSSION:

Subgroup participants were in general agreement with the MDC and RTP recommendations. The specific information that should be made available at the direction of customers is indicated in the recommendations below.

With respect to frequency and pricing of data provision, the group is recommending a departure from MDC recommendation 4-28, which recommended providing data twice a year for free and charging thereafter. The group felt that making such information available to retailers is an important consideration for an efficient market and that the incremental cost of data provision is small as long as it can be made available electronically through established links between LDCs and retailers. Consequently, the group recommends providing data as frequently as requested for free to retailers, with the expectation that such data can be delivered electronically in most situations. However, since data provision to small end-use customers is likely to be done through printing and mailing, this process should be limited to twice a year for free and that LDCs should be allowed to charge for providing data more frequently. The expectation is that this request limit would be exceeded rarely if at all and that most LDCs would not charge in any event. It's recognised that the cost of all basic data provision services would be covered in an LDC's basic wires charges if it is not charged for directly.

The group discussed whether both bill amount and usage amount should be provided and concluded that providing the bill amount could easily be more confusing than useful, since bills often have other charges on them that have nothing to with either electricity or wires charges. Also, if an LDC is billing on behalf of a retailer, providing bill amount could provide useful competitive intelligence to other retailers.

With regard to credit information, all participants present were in agreement that such information must be of a purely objective nature. LDCs should not be in the business of rating customer creditworthiness.

The group was also in agreement that a standard format should be used by all LDCs, except for interval-metered data. For the latter, it was agreed that each LDC would be able to provide the hourly usage data and other time-varying bill determinants in a format that is easily provided by the software used by the LDC to process meter data (e.g., MV90, Minimax, etc.) as long as the data can be readily accessed by retailers using nonproprietary software products.

With respect to information on meter type, LDCs typically record the manufacturer's model number but don't have explicit information on meter functionality. Providing explicit information about meter functionality would either require most LDCs to encode new information into existing databases, manually enter such information if requested by a customer or third party or communicate such information orally. Participants agreed that it should be sufficient for LDCs to simply provide the manufacturer's model number and that customers or retailers could obtain information on functionality by referring to manufacturer's documentation, contacting the manufacturer or using access to information that is generally available to meter experts. The group believed that this approach would be generally acceptable since only parties who are reasonably knowledgeable about meters or who have access to knowledgeable individuals would want meter information in the first place.

Concerning the period of time for which information should be provided, the group discussed the significant heterogeneity that exists across LDCs with regard to the number of billing periods that are kept easily accessible (e.g., on-line) and the length of each billing period. For example, two utilities might each keep only 12 billing periods of information on-line. However, if one utility bills every month and another bills every three months, the period of time covered by the 12 billing periods is one year in the first instance and three years in the second. Thus, if a standard was set in terms of number of months, say 24 for example, then one utility would need to provide data for 24 billing periods whereas the other would only provide data for 8 billing periods. If the former LDC was in the practice of only keeping 12 or 13 months of information on-line, it would have to access its archives to meet such a standard. After much discussion, the group agreed on a standard based on providing information that is easily available on-line. However, in no case should the period of time covered be less than one year. The maximum period of time covered would equal the time-period spanned by the maximum number of billing cycles that fits within the standard format file, which is recommended to equal 24. Thus, if an LDC billed every other month, a customer or retailer would receive data covering a minimum of one year and a maximum of four years, depending upon whether a utility kept only six billing periods on-line or kept 24 or more on-line.

RECOMMENDATIONS:

1. Customers have a right to request that customer-specific information be provided either directly to them or to one or more retailers of their choosing. Data provision to retailers will be provided at no incremental charge as frequently as requested. Requests to deliver data directly to end-use customers, if not delivered electronically through previously established links with the customer, will be honoured twice a year per account at no direct charge to a customer. Additional requests will also be honoured but LDCs will have the option of charging a reasonable fee for this additional service. *(Note: The OEB will need to decide whether the charge for additional requests should be based on a regulated price or is up to each LDC.)* A request is considered to be data delivered to a single address. Thus, a single request to send information to three locations is considered three requests.

2. For non-interval-metered customers, if a customer authorises release of his or her information, the following usage data will be provided to the designated party:

   (a) Customer account number.

   (b) Service address.

   (c) Billing address.

   (d) Current tariff.

   (e) Electricity usage amount for each billing period in kWhs.

   (f) Electricity usage amount for each TOU consumption period for each billing period, if TOU customer.

   (g) Multiplied kW for each billing period (if demand metered).

   (h) Multiplied kVa for each billing period (if available).

   (i) Date of actual or estimated meter read for each billing period

   (j) Indicator of read type (e.g., utility read, customer read or utility estimate) for each billing period.

   (k) The next scheduled meter-read date (or read cycle) and bill date.

3. If a customer authorises release of his or her information, the following meter data will be made available.

   (a) LDC meter number.

(b) Meter manufacturer.

(c) Manufacturer's model number.

(d) Manufacturer's serial number.

(e) Meter owner (if other than LDC).

(f) Last seal date.

4. If a customer authorises release of his or her payment information, the following information will be made available:

   (a) Whether or not the customer is currently in arrears and, if so, for how long.

   (b) The number of returned cheques associated with the customer over a designated period of time.

   (c) The number of times the customer has been disconnected for nonpayment over a designated period of time.

5. A customer's authorisation to release usage data will be construed to also authorise release of meter data. However, release of payment information must be based on a specific authorisation by a customer. That is, a customer's authorisation for release of customer-specific information should not be construed to authorise release of credit information unless the release form explicitly states that this is the case.

6. For interval-metered customers, the meter and credit information will be the same as for non-interval-metered customers. All items listed above under recommendation 2 will also be the same except for usage data, which will be reported on an hourly basis.

7. All non-interval data will be reported in a common format *(yet to be determined).* LDCs will have flexibility to provide interval data in a format that is easily created by the software the LDC uses to collect and process the data, but the format must be able to be read by nonproprietary, standard software packages (e.g., Lotus, Excel, etc.).

8. For billing-period-specific information, LDCs must provide data for 24 billing periods if readily available (e.g., maintained on-line). If 24 billing periods are not readily available, in no case can the number of billing periods provided represent less than one calendar year's worth of information (assuming that a customer has been on-line long enough to generate a year's worth of bills).

9. Information requests should be processed within ten business days of receiving a valid request.

IMPLEMENTATION ISSUES:

The rules and format for requests for customer information are covered elsewhere. As mentioned above, the data format and mode of communication for information provision are yet to be worked out.

Also, will rate charged for more than two deliveries to customers be a regulated rate?

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG1-12: LDC/retailer service agreement/contract.

- Is a formal contract between LDCs and retailers necessary/desirable or should/can all issues be covered as part of the settlement and/or distribution codes?

- If a contract is necessary, how uniform should the terms and conditions be across the province?

OPTIONS:

1. Formal contract (standard for all retailers and LDCs) making reference to the applicable Codes of Conduct.

2. Formal Contract: specific to each LDC and retailer.

3. No Contract (rely entirely on the set of Codes approved by the OEB).

BACKGROUND INFORMATION:

This issue was not discussed to any significant degree during the MDC/RTP process.

In the UK, it was initially assumed that all relevant concerns between retailers and LDCs could be handled through licences and codes and, therefore, there would be no need for a formal, legal contract between the parties. However, the parties came to realise that, in the absence of a formal contract, they could not rely on the normal commercial and legal tools available under contract law to remedy any problems. Instead, they would need to rely on a regulatory process centred around the threat of licence revocation. Amid fears about the reluctance of regulators to revoke licences for what might be perceived as relatively minor problems, a standard contract was developed and is now used to manage the LDC/retailer interface. Now there exists several different contracts among market participants. Specifically, each retailer signs a:

- Pooling and Settlement Agreement with the Pool

- Master Registration Agreement which largely focuses on settlement issues between retailers and distributors

- Distribution Use of System Agreement which covers distribution service issues between retailers and distributors

- Contracts with Data Collectors, Meter Operators and Data Aggregators.

The Pooling and Settlement Agreement and the Master Registration Agreement are standardised. The DUOS Agreement and contracts with data collectors, et al. are not standardised.

In New Zealand, there are also formal contracts between LDCs and retailers. However, this is even more necessary because of a lack of codes and licensing. Terms and conditions are similar across LDC territories, but there is no requirement for uniformity. In the early years of competition, some retailers felt that LDCs abused their dominant position by including onerous terms and conditions or by refusing to provide certain services through these contracts.

In California, LDCs and retailers sign contracts governing their interaction.

SUMMARY OF GROUP DISCUSSION:

Group participants were unanimous in agreeing that a service agreement between retailers and distributors covering settlement issues should be developed. Concern was expressed about the legal implications of having only the Code to fall back on if noncompliance action was required. The group felt that uniformity had its virtues, but also that local circumstances may vary and agreements may need to reflect this variation. The specific content of such an agreement must await completion of much of the work being done by all three subgroups.

RECOMMENDATIONS:

A formal contract between retailers and distributors covering key elements of the settlement process should be developed following completion of much of the work of the entire Settlements Task Force. The basic terms and conditions of the contract should be standardised across LDCs. Optional services and services where flexibility is allowed may also be covered in such a contract.

IMPLEMENTATION ISSUES:

Develop common terms and conditions once further Task Force work is complete.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG1-13: Establishing and updating prudential requirements between LDCs and retailers.

- What characteristics or variables should be used to determine the magnitude of security between LDCs and retailers?
- What form of security should be acceptable?
- What happens if a retailer defaults?

OPTIONS:

Magnitude of security:

1. Coverage equal to a frequently updated estimate of the revenue associated with all energy and/or wires charges (depending upon the billing option) billed by retailers to all of their retail customers for one, two or more billing cycles.
2. Less than complete coverage, by design.
3. Less than complete coverage (or excessive coverage) because of less frequent updating than in option 1.

Form of security:

1. Commercial bond rating
2. Conventional forms such as cash, letter of credit, etc.
3. Prepayment in place of deposit
4. Daily settlement in place of deposit
5. Some combination of the above
6. Any of the above from a third-party clearinghouse rather than directly from each retailer.

BACKGROUND DISCUSSIONS:

LDCs require some form of payment security when retailers' bill on their behalf since LDCs must pay the IMO and cover their costs of wires services whether or not they are paid by retailers. When retailers bill for energy and/or wires charges, LDC risk may increase because LDCs lose the ability to impose deposits on end-use customers and retailers may default on payment whether or not they are paid by customers. Prudential rules must be competitively neutral and not lead to a major entry barrier in the market.

This risk can be mitigated by standard forms of security between LDCs and retailers. However, transaction costs and the cost of security may be prohibitive if all retailers must establish separate security arrangements with every LDC. The Retail Technical Panel of the MDC recommended in section 3.2.4.4 of the RTP Final Report that the formation of a retailer's Prudential clearinghouse be considered in order to reduce transaction costs. This would allow a central clearinghouse for all LDCs.

There is little guidance to be gained from the Ontario gas industry on the issue of prudential requirements because of the historical practice that gas LDCs were the only parties that billed end-use customers. Now that retailers have gained the right to bill customers for gas and LDC charges, prudential concerns should be similar to those for the electricity industry.

Relevant MDC/RTP Recommendations:

MDC recommendation 4-8, Second Interim Report:

We recommend that rules be developed to ensure that the local distribution company's security of payment is not decreased by the introduction of competitive retailing, to protect competitive retailers from customer nonpayment and to protect the customer from the risk of having to pay twice if his retailer defaults. This may require substantial qualification and indemnification rules for competitive retailers before they may be licensed to participate in the market.

RTP Recommendation 3-15:

The RTP recommends that a working group be organised under the direction of the OEB to develop a workable, competitively neutral, standardised approach to prudential requirements for retailers designed to mitigate default risk to LDCs. The approach should be based on the principle that risk varies with the credit worthiness of retailers and the magnitude of loss in the event of default. Thus, the nature and form of security should vary across retailers according to these two parameters. The working group should also examine options that reduce the high transaction costs associated with a single retailer needing to make separate security arrangements with multiple LDCs.

SUMMARY OF GROUP DISCUSSION:

Agreement was quickly reached that:

1. LDCs should require a prudential guarantee from retailers.

2. Conventional methods such as cash, letter of credit and power bond are acceptable.

3. Bond ratings and other credit opinions could be considered by LDCs but these were perceived by group members to represent a greater risk than deposits.

4. Interest should be payable on cash deposits.

5. LDC should be required to monitor deposit vs. risk.

6. Customer deposits should be used to pay final LDC bills with any balance being sent to customers.

A sample payment timeline was developed to assess risk to LDCs. This timeline indicated that, based on a 30-day billing cycle, LDC risk is about 60 days, since it takes roughly 30 days beyond the bill date for an LDC to become aware of a default situation and to determine whether or not remedy is possible. For a 60-day billing cycle, the risk period is 90 days, etc.

Some retailers felt that prudential requirements equal to 60 days or more of receivables might pose an undue burden on retailers. The subgroup discussed ways to reduce the length of time (and therefore the magnitude of receivables) that would have to be covered by security arrangements. After discussing many scenarios, it was determined that the period could not be shortened. However, prepayment or pay as you go might reduce the cash/credit requirements of a retailer. Prepayment based on an estimate exposes LDCs to the accuracy of the estimate vs. the actual amount for the settlement period of about 15 days. Daily settlement (pay as you go) exposes LDCs to the accuracy Vs the estimate for the settlement period of about two days. This method assumes daily transfer of payments from retailers to LDCs, which might be a burden to either party.

In order to keep the magnitude of prudential requirements as small as possible, the subgroup agreed that LDCs should bill each retailer every 30 days based either on an actual read or an estimate. In other words, LDCs should not be allowed to bill on a 60-day cycle. This recommendation was discussed in other subgroup meetings and at the Task Force level and most others felt that this would be onerous on many LDCs and is unnecessary since retailers can mitigate the cost of security by billing their customers more frequently than they are billed by LDCs. In other words, even if an LDC only bills once every 60 days, thus requiring that retailers post 90 days of security, a retailer can manage the cost of such arrangements by billing their customers every 30 days (based on estimates).

Another method of minimising the magnitude of required security is referred to as a “lock box” collection process. With this approach, end-use customers would pay their bills to a qualified third party who would, in turn, make payment to distributors for all services rendered before paying the residual amount to the relevant retailer. This approach is used in the newly restructured New York market. This approach should lower nonpayment risk to LDCs to a level comparable to that of their current end-use customer mix, since the third-party collections agency is simply collecting and passing through the revenue provided by end-use customers. While there is still some risk of fraud, the business risk faced by a collection agency should be less than that faced by electricity suppliers. Consequently, the amount of required security should be less than if the security was posted by a retailer.

Further discussion took place concerning what happens if a retailer defaults on a payment. It was agreed that a remedy period should be set. The subgroup agreed on five (5) business days. If a retailer is still in default after the remedy period, the retailer’s customers will be notified by the LDC that they will become Standard Supply customers unless they sign with a new retailer before the next billing date. If they sign with a new retailer, the start period could be the last reading (final) for the old retailer.

Although there was general agreement that the amount and form of security should be based on the magnitude of outstanding receivables and the probability of default, it is difficult to decide how to operationalise these concepts. The magnitude of outstanding receivables at risk is a function of:

- The billing option (e.g., retailer full or partial consolidated billing, split billing, LDC consolidated billing)
- The wholesale spot price
- Under LDC consolidated billing, the difference between the price offer of a retailer compared with the wholesale spot price
- The average consumption per billing period of the retailer's customer base, which varies seasonally.
- The number of customers served by a retailer

All of these factors are very dynamic, changing significantly from one billing period to another, if not daily.

The probability of default by a retailer is a function of:

- Financial health of the retailer and its parent company (if the distributor has recourse to the parent company for the retailer's debts).
- Procurement practices of the retailer and the portion of the customers' contracts that the retailer has hedged.
- Incidence of default by the other parties to the hedging mechanisms employed by the retailer.
- Incidence of nonpayment by the retailer's customers.
- The amount that the retailer owes the distributor (i.e., the amount at risk).

These factors also change frequently. Obtaining information on some of these factors could be difficult for an LDC due to commercial sensitivity (e.g., the nature of procurement practices and hedging strategies).

The recommendations presented below take into consideration many of the factors outlined above and propose a simplified approach to estimating the magnitude of receivables. As seen in recommendation 8, LDCs are provided with some flexibility to assess the probability of default, and therefore the type of security, that will be required from each retailer.

RECOMMENDATIONS:

1. The maximum amount of security required to be posted by a retailer should be based on an estimate by an LDC of the expected revenue exposure and the risk of default by the retailer. Consequently, the magnitude of required security will vary with the type of billing in place and the creditworthiness of the retailer. The amount required will be highest for full and partial consolidated billing by retailers, lower for split billing and even lower for consolidated billing by LDCs. The security amount should be based on an estimate of usage for a billing period plus 30 calendar days (e.g., 60 days' worth of consumption for monthly billing, 90 days for bimonthly billing, etc.).

2. For full or partial retailer consolidated billing, an estimate of the maximum magnitude of receivables at risk must be determined as follows:

   (a) Estimate the total monthly bill (all commodity and non-commodity charges) for an average customer served by a retailer for the month in which the bill is expected to be highest during the year. The highest expected total bill will occur in the billing period where the product of usage and expected wholesale spot price are the highest. The usage estimate must be based on values for an average customer. If a retailer is serving a heterogeneous group of customers, an LDC may develop usage estimates for several different customer segments (e.g., domestic customers with and without space heating, small commercial, medium commercial, etc.). Wholesale price estimates must be based on a reasonable forecast at the outset of the market. Once the wholesale market has been operational for some time, average monthly wholesale prices for a previous year may be used to select a price estimate.

   (b) Multiply the estimate in step 2.(a) by the number of customers served by a retailer. In the event that segment-specific estimates are used, multiply the number of customers in each segment by the estimate for that segment and add up the segment totals.

   (c) In the event of monthly billing, double the amount determined in step 2.(b). In the event of bimonthly billing, multiply the amount in step 2.(b) by 1.5. In the event of quarterly billing, multiply the amount by 1.33.

3. For the split billing option, the same step-by-step procedure outlined above should be used except that the magnitude of receivables must be based only on the commodity portion of the bill, estimated at the wholesale sport price, rather than on the entire bill amount.

4. The magnitude of security required for LDC consolidated billing will vary with the type of billing service offered.

   (a) For rate-ready options that have a positive adder or a multiplier greater than or equal to 1.0, no security is required since an LDC is never in a negative cash position vis-à-vis a retailer (e.g., the amount billed to a customer will always be greater than the cost of supply based on the wholesale spot price).

   (b) For fixed price, multiplicative or additive rate-ready pricing algorithms, the magnitude of receivables should be estimated by multiplying an estimate of the monthly usage for an average customer times the difference in the wholesale spot price and a retailer's price to the end-use customer for the month where the magnitude of the product of these two estimates is greatest (e.g., for the same period as described in 2.(a) above).

(c) Proceed as with steps 2.(b) and 2.(c), but using the value in 3.(b) as the average customer value.

5. Any deviations from the rules laid out in steps 2 through 4 must be approved by the OEB.

6. Since retailers' market share may change frequently, LDCs must periodically update the forecast of aggregate usage associated with customers served by each retailer. LDCs may update the requirements as frequently as necessary or desired, but must update the aggregate estimate at least once every three months, using the procedures outlined in rules 2 through 4 and the most recent value for total customers served by each retailer. If the amount of required security has increased by more than 10 percent over the amount currently in place, retailers will have 20 business days to meet any new requirements imposed by an LDC. If the amount of required security has fallen, an LDC must notify the retailer immediately. In the event that the security arrangements involve cash deposits held by an LDC, the LDC must return the excess amount to a retailer within 20 business days of the date on which the amount was determined.

7. Irrevocable letter of credit, power bond, cash and "lock box" arrangements are considered acceptable for meeting prudential requirements and must be accepted by all LDCs. LDCs must pay interest on cash deposits. The interest rate payable to retailers on cash deposits held by LDCs is negotiable but LDCs should not be allowed to make money on any spread between interest they pay retailers and interest they earn on cash deposits. Retailers may require that cash deposits be held in specific interest-bearing investment accounts as long as LDCs have exclusive access to sufficient funds to cover the security requirement.

8. LDCs may accept bond ratings or other credit ratings from retailers in meeting the prudential requirement. Recognising that LDCs will vary with respect to the acceptable risk they are willing to take and the manner in which they may interpret rating information, the acceptable bond ratings or other ratings are at the discretion of an LDC. The OEB may wish to set minimum levels for standard credit ratings that LDCs will be allowed to accept.

9. If retailers organise and become members of a "prudential clearinghouse" that is willing to take responsibility for security for its members, LDCs must accept prudential arrangements with the clearinghouse in lieu of arrangements with individual retailers as long as the degree of security is comparable.

10. A remedy period of five business days should be allowed if a retailer defaults on a payment date. If the account still remains unpaid and the retailer and LDC have not agreed on a remedy after five business days, the LDC may inform the retailer's customers that they will become Standard Supply customers as of the next bill rendered unless they sign with a new retailer. Any money paid by the customer to the LDC for the period billed to the retailer will be paid to the retailer. The LDC should rely on the prudential requirements with the retailer for settlement.

11. LDCs may charge retailers interest on any amounts not paid by the due date. The interest rate will equal the bank-borrowing rate for the LDC or may be negotiated between LDCs and retailers.

IMPLEMENTATION ISSUES:

The OEB may wish to consider setting minimum credit ratings below which LDCs would not be allowed to accept credit ratings as the only form of security offered by a retailer.

VOTER SUMMARY:

Nineteen in favour.

DISSENTING OPINIONS:

One LDC member favoured having the prudential requirements in recommendation 1 equal the billing period plus 60 days, not 30 days.

ISSUE STATEMENT:

Issue SG1-14: What should the process be for dispute resolution between LDC and retailers?

OPTIONS:

1. Include rules and procedures for all disputes in the Settlement Code.
2. Include only procedures for those disputes not covered elsewhere in the Distribution Licenses or Codes.

BACKGROUND INFORMATION:

The RTP recommended that all retailers and distributors be required to ascribe to an independent dispute resolution mechanism of their choice. These may include an independent provider, the existing process used by the Ontario Energy Marketers Association (OEMA) expanded to include electricity markets, a voluntary organisation similar to OEMA but exclusively for electricity, the Municipal Electrical Association, the OEB or MEST, the Better Business Bureau or some combination of the foregoing at the choice of the retailer.

Dispute Resolution Process: Implicit in recommendation 4-7 is that a dispute resolution process exists to which customers can turn if they wish to protest transfer constraints placed on them by their current retailer. Section 7 of this report discusses dispute resolution procedures. The OEB must provide clear guidance regarding how such disputes will be handled so that LDCs are not forced to arbitrate matters between consumers and retailers.

Dispute of Account—where customers involved in a dispute with a retailer cannot be disconnected prior to completion of dispute resolution procedures.

Recommendation 7-30:

The RTP recommends that retailers be required to subscribe to an independent third-party dispute resolution mechanism. The specific dispute resolution vehicle should be at the choice of the retailer and follow certain guidelines set by the OEB.

Section 23 of the Transitional Distribution License states that a Licensee shall:

1. Establish proper administrative procedures for resolving complaints by consumers and other market participants' complaints regarding services provided under the terms of this license;
2. Publish information which will facilitate its customers accessing its complaints resolution process;
3. Refer unresolved complaints and subscribe to an independent third-party complaints resolution agency which has been approved by the Board;

4. Make a copy of the complaints resolution procedures available for inspection by members of the public at each of the Licensee's premises during normal business hours;

5. Give or send free of charge a copy of the procedure to any person who reasonably requests it; and keep a record of all complaints whether resolved or not including the name of the complainant, the nature of the complaint, the date resolved or referred and the result of the dispute resolution.

SUMMARY OF GROUP DISCUSSION:

The group discussion was wide ranging from how does the customer know about the dispute mechanism to do we need to list anything in this code or just let the other codes and licenses deal with it. It was decide that generally the licences and other codes would provide the dispute process but we needed to identify things specific to this code and its application. Those issues were billing disputes and business processes/conduct. The issue on billing centred around the preventing retailer or LDC withholding payment for an aggregate bill when the dispute involved only one or two accounts. The committee felt that setting time lines to settle the disputes on billing was not necessary and would rely on the good faith and business practises of the LDC and retailer.

RECOMMENDATIONS:

Any disputes between retailers or consumers and distributors concerning the implementation of a distributor's responsibilities under this Code shall be settled according to the dispute mechanism specified by the Board in section 23 of the Transitional Distribution Licence or, once permanent licences are issued, by the relevant section of the permanent licence. Disputes concerning the settlement amount billed by a distributor to a retailer for an individual customer account shall not affect a retailer's obligation to make payment for any other accounts or amounts due for other services billed on the same settlement invoice.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

APPENDIX B

Subgroup 2: Customer and Competitive Retailer Billing and Receivables

ISSUES LIST

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2. Issue SG2-2: Split-bill option ... B-4
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8. Issue SG2-8: Risk mitigation procedures ... B-25
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10. Issue SG2-10: Should an LDC be allowed to refuse to reconnect a customer unless the customer has paid all past due bills associated with wires charges and standard supply? ... B-29
11. Issue SG2-11: What guidelines should be set for the timing and notification of disconnection? ... B-32
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ISSUE STATEMENT: ***(Final)***

Issue SG2-1: Retailer consolidated billing.

- Should retailers be allowed to provide a single bill to an end-use customer that combines both electricity supply and distribution charges?

OPTIONS:

1. Retailers should be allowed to offer customers a single bill that includes distribution charges as well as electricity charges.

2. Retailers should be allowed to bill for electricity supply but not for distribution services.

3. Only LDCs should be allowed to bill customers (at least for some transition period).

BACKGROUND INFORMATION:

MDC recommendation 4-10:

We recommend that all local distribution companies be required, at the customer's request, to send the customer's spot-price bill to a designated licensed retailer, who would be responsible for paying the LDC for the amount of that bill. The retailer and consumer would then be responsible for settling their bilateral contract totally independent of the LDC.

The above recommendation, along with RTP recommendation 3-2 which states, in part, that LDCs must be capable of "Sending bills to and receiving payment from retailers when directed to do so by customers," imply that retailers should have the option of offering a consolidated bill to end-use customers.

Most, but not all jurisdictions, currently allow this. It is the rule in California, New Zealand, Australia and the UK. To date LDCs still maintain a monopoly over billing in New Jersey and, we believe, Massachusetts although the expectation is that this is transitory.

Historically, in Ontario gas retailers have not been allowed to offer consolidated bills, but they now can or soon will be able to.

SUMMARY OF GROUP DISCUSSION:

This issue was primarily discussed in conjunction with issues SG2-2 (split bills) and SG2-4 (LDC consolidated bills). Two LDC representatives favoured retaining an LDC monopoly over billing at least during a transition period as a means of helping to ensure recovery of development costs for new billing systems. This would also ensure that retailers have access to billing services without the need to negotiate with LDCs and without the barrier that "first movers" would face in terms of having to pay for development costs under a voluntary program.

Retailers favour the right to offer a consolidated bill. Retailers are concerned about the magnitude of the avoided cost credit they would receive if they do billing for LDC charges. This is a rate issue that will be taken up by the Board at some future date.

One LDC representative favoured allowing retailers to bill on behalf of LDCs only if the retailer agrees to unbundle their bills and show the wires charges as a separate, identified

RECOMMENDATIONS:

1. Retailers should be allowed to offer a consolidated bill to customers that includes all charges for delivered electricity (e.g., generation, transmission and distribution). In the event that a customer or retailer (on behalf of his or her customer) selects this option, an LDC must direct the settlement bill directly to the retailer.

IMPLEMENTATION ISSUES:

The OEB must determine the magnitude of avoided cost credit paid by LDCs if retailers offer consolidated bills.

VOTER SUMMARY:

The majority of Task Force members favoured this recommendation but two LDCs favoured option 3. One LDC representative indicated that he would favour the recommendation only if the wires charges were shown explicitly on the retailer's bill.

DISSENTING OPINIONS:

See voter summary above.

ISSUE STATEMENT: ***(Final)***

Issue SG2-2: Should all LDCs be required to offer a split-bill option where charges for energy calculated at the spot price are directed to a customer's electricity retailer and all wire's and related charges are billed to customers directly by the LDC?

OPTIONS:

1. Mandatory provision by all LDCs with costs included in base rates.

2. Offered on a voluntary basis and paid for by those who want it.

BACKGROUND INFORMATION:

RTP recommendation 3-14 recommends that all LDCs offer split billing as a mandatory option. The split-bill option is offered in other jurisdictions. Indeed, in California split billing is the default billing option for customers/retailers who do not select consolidated billing. It is currently unknown how many customers are on split billing in California or elsewhere but it is believed to be few. It is thought that some large customers may place a higher value on dealing directly with their local wires company on pricing and billing issues for network services, rather than through a retail intermediary.

Since LDCs must unbundle bills anyway, the RTP felt that the added burden of providing split billing was not so great as to outweigh the potential value that this option could provide to selected customers.

According to one group member, in a very recent survey by the Ontario Energy Marketers' Association, retailers representing 90 percent of the competitive gas retail market indicated that the split-bill option was not desirable, would hamper unbundling and would cause retail customers to pay twice for billing services.

As of the end of March 1999 (about a year into direct access), roughly 130,000 accounts had switched suppliers in California. Of these, about 40 percent used consolidated billing through the local LDC, about 45 percent used retailer consolidated billing and about 15 percent used the split-bill option. In Illinois, where competition is currently only available for large commercial/ industrial customers, the majority of customers use the split-bill option. In Pennsylvania about half of customers who have switched use the split-bill option.

SUMMARY OF GROUP DISCUSSION:

Most group members felt that this option would be rarely chosen and that making it a mandatory service could impose unnecessary costs on LDCs. However, evidence from other jurisdictions cited above suggests that it is an attractive option for some customers and/or retailers. Participants felt that this should not be a default option. It was pointed out that the concept of a default billing option is largely irrelevant since each retailer will arrange with each LDC to have their own default in the sense that a specific option will be assigned to a customer served by that retailer in the absence of a designation to the contrary.

Customer convenience is not the only important consideration when deciding whether or not to offer split billing. Another one is the fact that split billing significantly reduces the prudential requirements of retailers. Given that wires charges are roughly half the cost of delivered energy, the split-bill option offers retailers the opportunity to avoid posting security for a significant portion of the cost of delivered energy.

RECOMMENDATIONS:

1. Split billing, with retailers billing only for the commodity and LDCs billing for all non-commodity charges (including transmission), must be accommodated by all LDCs. In the event that this option is chosen by a customer or retailer, an LDC must calculate the commodity portion of a customer's bill using the wholesale spot price and render that bill to the appropriate retailer. Charges for non-commodity services will be included on a bill rendered by an LDC to an end-use customer.

2. As indicated in the recommendations for issue SG2-6, with split billing, each party will be responsible for customer nonpayment risk for the bill they render.

3. Retailers will be responsible for posting security with an LDC for the commodity portion of the bill in order to cover retailer default risk. The magnitude and nature of security arrangements are covered under issues SG1-13.

IMPLEMENTATION ISSUES:

LDCs must modify billing systems to issue two bills per end-use customer (one to the customer and one to the retailer).

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG2-3: Equal payment billing by LDCs:

- Should LDCs be *required* to offer a balanced payment option to end-use customers for any bill they directly render to a customer?
- Should LDCs be *allowed* to offer a balanced payment option to end-use customers?
- If equal payment billing is offered to end-use customers, must it also be offered to retailers on the same terms?

OPTIONS:

1. An equal payment or billing plan in this context means that an LDC would produce an estimate of a customer's bill for a period of time (perhaps, but not necessarily, a year) and would bill a customer for an equal amount each billing period, with a true-up payment at the end of the agreed time equal to any difference between the estimated bill and the actual amount owed for the entire time. If both price and quantity vary during the period, equal billing would smooth volatility associated with both variables but the customer would always eventually pay the full amount owed. Policy options associated with this issue include:

2. Mandatory provision of the equal billing option by LDCs for any bill they render directly to end-use customers or to retailers.

3. Mandatory provision of equal billing but only for bills rendered to end-use customers, not to retailers.

4. Voluntary provision of equal billing to end-use customers or retailers.

5. Prohibition of equal billing by LDCs.

6. For any of the above options, there could be limits set on how long the equal billing period should be, on whether true-ups would be required if the difference between actual and estimated amounts exceed a certain level and other factors.

BACKGROUND INFORMATION:

There was some debate at the MDC regarding whether or not LDCs should be allowed to provide balanced payment billing. Some members felt that this would be anticompetitive (e.g., this was a competitive service that only competitive retailers should be able to offer). However, the majority of MDC members felt that this should be an option that LDCs may provide at their own discretion. There was no formal recommendation one way or the other.

In discussions at the MDC concerning potential customer dissatisfaction with bill volatility, the MDC recommended a "smoothed" wholesale spot-price pass-through as a way of mitigating the impact that a pure spot-price pass-through would have on residential customers that are accustomed to annually set flat pricing schemes. The RTP noted that implementing spot-price smoothing would introduce new practices for LDCs, would require some entity to make an official price forecast and would not mitigate usage volatility. The RTP responded with a recommendation that the smoothing could be accomplished through equal billing/payment plans that most LDCs already had in place.

SUMMARY OF GROUP DISCUSSION:

Retailer and LDC group members differed strongly in their opinions on this issue.

LDC representatives feel strongly that offering equal billing is an option that they have always had and that they should continue to have. It should not be mandatory, but it should definitely be allowed so that they can smooth customer payments and help mitigate any cash flow problems during peak consumption months. Without this tool, LDCs could easily experience a significant increase in customer complaints from Standard Supply Service (SSS) customers and a potential increase in late payments or defaults during high consumption months. LDCs feel that this is not a pricing issue, but a billing and customer service issue and that they should have discretion over such matters in order to maintain reasonable levels of satisfaction among SSS customers. At least one LDC representative questioned the authority of the OEB to regulate billing practices.

Retailers feel strongly that equal billing is a value-added service that will compete directly with fixed-price offers from competitors and that will make it difficult for competitors to sufficiently differentiate their services as a means of attracting customers away from Standard Supply. One retailer representative recommended that this issue not be decided until the form of SSS is determined by the OEB. This individual suggested that he would be more willing to accept equal payment by LDCs if SSS was a fixed-price option rather than a spot-price pass through. Other group members wondered why SSS as a fixed-price option with equal billing wouldn't be viewed as even more anticompetitive than a spot-price pass through with equal billing. A retailer representative also claimed that this option exposes LDCs to additional nonpayment risk and could potentially increase the IMO prudential requirements imposed on LDCs. It was also pointed out that this imposes a need for LDCs to develop a process to forecast volume and price for customers using this option.

The idea of placing constraints on the characteristics of equal billing was not discussed. For example, OEB guidelines or requirements could be established where adjustments in bills would be instituted if spot prices differed by a certain percent from the values that underlay (explicitly or implicitly) the current projections.

Several LDC representatives objected to the idea of offering equal payment billing to retailers. One group member was worried that doing so offers retailers an added service that increases LDC risk unless prudential requirements are adjusted appropriately. This individual also commented that doing so might introduce more complications into the process than are necessary.

RECOMMENDATIONS:

This issue concerns billing services for end-use customers, not settlement between LDCs and retailers. Therefore, it is recommended that this issue not be included as part of the Retail Settlement Code.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Twelve in favour of the recommendation; three against; two indifferent.

DISSENTING OPINIONS:

The three dissenting Task Force members preferred to include a recommendation in the settlement code confirming an LDC’s right to offer equal payment billing to end-use customers.

ISSUE STATEMENT: ***(Final)***

Issue SG2-4:

- Should consolidated billing by LDCs on behalf of retailers be a mandatory service for all LDCs?
- If not, should LDCs be required to make a “good-faith” effort to offer such services?
- If yes, how should good-faith effort be defined?

OPTIONS:

1. “Consolidated billing” in this context means that an LDC will bill end-use customers on behalf of retailers according to one of several methods outlined below. Consolidated billing and “aggregate billing” are not the same thing. Aggregate billing means producing a single bill for multiple customers. The following options were considered:

2. Mandatory consolidated billing services by LDCs, where bill amounts would be calculated by retailers and passed through as a line item on LDC bills. (Hereafter referred to as the “bill-ready” option.)

3. Mandatory consolidated billing by LDCs where LDCs calculate retailer bills based on any pricing and contract terms designated by retailers. (Hereafter referred to as “full rate-ready” billing.)

4. Mandatory consolidated billing by LDCs but only based on a simple calculation of a price times quantity where retailers could modify prices on a periodic basis. (Hereafter referred to as “simple rate-ready” billing.)

5. Options 1 and 3 combined, which would have LDCs calculate bills for energy based on a single average price but would also allow retailers to pass through charges for additional services they may provide to customers.

6. Any of the above offered and agreed to on a voluntary basis through a good-faith negotiation between LDCs and retailers. All development, fixed and operating costs for these services, would be paid for only by those who desire them and steps would be required to ensure no cross-subsidisation of such services by SSS customers.

7. Monopoly provision of billing services by LDCs, at least during a transition period. In other words, not only would LDCs be required to offer consolidated billing on behalf of retailers, but they would be the only ones allowed to bill end-use customers (e.g., retailers would not be able to bill end-use customers directly themselves).

BACKGROUND INFORMATION:

The MDC Second Interim Report established some general principles:

- Customers should at least have the option of receiving a single bill. The MDC report indicated that many customers have expressed the preference for one bill for their network and energy charges.

- The MDC report also noted that some retailers argued that LDC billing on their behalf would facilitate market entry and competition overall.

Weighing the desire of some retailers to have LDCs as billing agents and the potential burden that this option would impose on LDCs, the MDC decided not to recommend that this option be mandatory, as indicated in the following MDC/RTP recommendation:

RTP recommendation 3-14:

> . . .The RTP does not recommend requiring all LDCs to bill on behalf of competitive retailers. However, LDCs should make a good-faith effort to offer such services if requested by retailers if all development and ongoing costs are recovered from those who use the service.

LDC consolidated billing is similar to the gas industry's ABC-T service. To date gas utilities have been providing the entire billing process on a bundled basis, including meter reading, bill calculation, bill printing, payment processing, collections and write-off for bad debts. Gas utility charges for ABC-T are reviewed by the OEB in rate cases for appropriate recovery of costs, but the charges are not "regulated" in the traditional sense. This approach has been affordable for retailers in the gas industry in part because there are only two gas utilities, with each serving a large number of consumers and retailers. Therefore, the incremental cost of providing billing services is reasonable on a per customer basis in the gas industry.

On the other hand, there are a large number of electric utilities. Some LDCs have a very small franchise area where only a few (if any) customers may switch to competitive retailers. It could be very costly and inefficient to require all LDCs to incur significant costs in system modifications to accommodate billing on behalf of retailers. The incremental cost could be very high on a per customer basis.

If an LDC has the system capability and resources, it may wish to make more efficient use of its system by contracting its billing services to retailers or other LDCs. If a competitive market for billing services emerges, LDCs and retailers can choose to contract to a third-party billing agent to carry out consolidated billing for either party.

Looking at other jurisdictions, requiring LDCs to offer consolidated billing is the rule in California, New Jersey and Pennsylvania. Indeed, in New Jersey, retailers are not allowed to offer consolidated billing so LDCs must.

SUMMARY OF GROUP DISCUSSION:

The primary advantages to offering LDC consolidated billing include:

- Minimisation of entry costs for retailers since they would have ready access to billing services. (Note: Third-party billing companies also offer this advantage.)

- Minimisation of prudential requirements posted by retailers relative to either split billing or retailer consolidated billing.

- Retention of the authority to disconnect a customer for nonpayment, thus reducing nonpayment risk in the market when compared with retailer consolidated billing, where disconnection is not an option under the *Electricity Act.*

- Elimination of customer nonpayment risk to retailers, since LDCs logically would take on this risk (and would factor the cost of such risk into their charges for billing on behalf of retailers).

- Faster payback on investment in new billing systems that many LDCs must develop to support the market, since they will be able to sell their services to retailers.

- Potentially shorter read-to-bill cycles for LDCs and retailers under certain rate-ready billing options. For example, if an LDC calculates bills on behalf of a retailer based on a simple (traditional) constant rate, bills to customers can be issued according to the same historical practices (e.g., one or two days after a meter read) rather than delayed while waiting for information from the IMO to calculate the NSLS and issue bills based on the wholesale spot price. (Other types of rate-ready billing that are based on deviations from the spot price would still require some delay.)

The primary disadvantages of this approach include:

- The development costs imposed on LDCs to build the capability to provide such services.

- Potential delays in billing under bill-ready scenarios if retailers must acquire usage information from LDCs, calculate bill amounts and communicate these amounts back to an LDC before bills can be issued.

The subgroup and full Task Force discussed this issue at great length over several meetings. Among the points raised during these discussions were:

- Few if any utilities currently have billing systems that would easily accommodate option 2.

- Accommodating option 3 would be easy from a computational standpoint since all current billing systems calculate bills based on average price and usage. Only minor changes would be required to update prices on a regular basis and to accommodate multiple prices for customers in the same rate class. However, for LDCs that do not currently bill on behalf of outside suppliers, internal accounting and business processes would need to be established in order to ensure that costs and revenues are tracked by retailers and that retailers get paid what they are due in a timely manner.

- Option 1 is obviously simple computationally and most if not all billing systems can easily accommodate the addition of a single line item on a bill. However, as discussed in the previous bullet point, LDCs who do not currently bill on behalf of other municipal departments or outside suppliers will need to establish accounting and remittance systems in order to provide this service. Furthermore, with option 1 systems will need to be developed to receive the relevant bill information from retailers on a daily basis and to transmit usage information to retailers. This will delay billing to end-use customers.

- Monopoly provision of billing services by LDCs, option 6, was seen as a means of helping to ensure recovery of development costs for new billing systems, at least during a transition period. It would also ensure that retailers had access to billing services without the need to negotiate with LDCs and without the barrier that first movers would face in terms of having to pay for development costs under a voluntary program without knowing what their market share will be and without easily being able to share costs with other retailers unless they team up in their negotiations with LDCs.

- All participants recognised the need to ensure that any voluntary provision of services by LDCs must be paid for by those who request them and that there should be no cross-subsidisation of these services by SSS customers.

Following initial discussion of this issue, two subgroup members submitted the following written comments. The first bullet was from a retailer representative while the remaining comments were from an LDC representative on the committee.

- There is a hazard to consider in allowing LDCs to build billing systems to support consolidated billing and as the market matures, there could be additional stranded costs from billing systems that have been abandoned.

- Should retailers only pay for incremental costs? Why not a portion of the capital and associated carrying costs? How do you partition these among the various retailers? Do you recalculate the capital contribution when there are new entrants? If not, is this discriminatory?

- Even if the development and implementation costs are all fully allocated from the retailer who requests the service, there are future maintenance costs that need to be allocated to the particular system function.

- If an LDC is faced with requests from different retailers and they all have different requirements, what is the priority of the requests? By order of simplicity or complexity (the LDC won't know until it has undertaken the study)? By order of size of retailer?

- There is no practical way of anticipating all the current and future services to be provided by all the retailers. Some of these may be simple as far as bill calculation is concerned, while others may require major modifications to the billing system. It may seem straightforward for the LDC to just develop the necessary system function and then charge the retailer for the cost. In practice, much of the cost is not visible. First of all, the LDC computer system personnel may spend significant effort to analyse the retailer's requirements and the development work may not proceed for whatever reason. Would the cost be charged to the retailer (who had not received the system function required) or should the LDC allocate the cost to operating expense (borne by all customers, effectively)?

In discussing the advantages of LDC billing to retailers, the following points were made:

- ABC-T billing has worked very well for retailers in the gas industry and has given retailers time to establish their market presence and to prepare for the new opportunities they now (or will soon) have to offer billing on their own.

- LDC billing facilitates market entry not only by offering a convenient source of billing services to retailers but also by providing reassurance to customers through LDC brand equity and familiar service delivery. In light of the availability of third-party billing firms, the latter factors are perhaps more important than merely having a convenient billing service available.

- A major advantage of LDC consolidated billing is that it significantly reduces (but does not entirely eliminate) the magnitude of prudential requirements imposed on retailers. The reason prudential requirements are not entirely eliminated is that, at certain times of the year, an LDC will still be in a negative cash position vis-à-vis a retailer. For example, if a retailer's offer to an end-use customer involves a fixed price for an entire year (say 4¢/kWh), if the spot-market price is above that amount during a specific billing cycle (say 4.2¢/kWh), an LDC will collect less money from a customer than the cost to supply that customer. In this example, a retailer owes an LDC 0.2¢/kWh for that billing period and there should be some security arrangement between the LDC and retailer to cover that risk. This issue is discussed further below.

At the Task Force meeting on August 11, a decision was made favouring mandatory consolidated billing by all LDCs. The Task Force agreed that, at a minimum, bill-ready billing should be provided. Subgroup 2 was asked to flesh out the details of this option and to consider whether simple rate-ready billing should also be provided.

At the subgroup meeting on August 18, retailer representatives suggested that three rate-ready options be considered along with bill-ready capability. The three options would all have a variable and fixed component, thus requiring two lines on each bill to cover services provided by a retailer. The first line would post the variable component and the second a descriptor along with a monthly fixed fee. For the variable component, the three options are:

1. A fixed price expressed as ¢/kWh multiplied times usage for the billing period.

2. A percentage mark-up (or mark-down) on the spot price times usage.

3. An adder (+ or -) to the spot price times usage.

Retailers prefer that under each rate option, the price would be allowed to vary by customer and could be changed as often as once per billing cycle. All parties agreed that changes would involve a transaction fee so that frequent changes might be costly. In theory, although highly unlikely in practice, every customer served by a retailer could have a different price and that price could change frequently. Consequently, the billing software used by LDCs would need to identify whether a customer is served by a retailer and then look up in a table what price and what price algorithm should be used. LDCs warned that the development cost to accommodate the flexibility outlined above will be costly and time consuming. LDCs are also very concerned that maintaining databases in light of frequent price changes will be costly and that the necessary "lookups" required to process a bill each time will slow down processing time. Retailers argue that, in light of the fact that the spot price changes each month, the necessity of looking up a new rate for each customer for each month is little different than the new requirements that LDCs face in calculating bills using the NSLS. As mentioned previously, if option 1 is used, this approach also offers the advantage of being able to issue bills to customers more quickly than under the NSLS approach, since the price is known at the time of the meter reading.

Another issue discussed by the subgroup concerned the definition of good-faith effort in the event of voluntary provision of services by an LDC. This was discussed at the time that the subgroup was considering voluntary, rather than mandatory LDC billing. The principles agreed to were that a good-faith effort should involve an offer by an LDC within a reasonable time frame to provide services requested by a retailer at a price that, at a minimum, fully recovers the cost of the incremental services (e.g., there is no cross-subsidisation). A good-faith offer must not discriminate among retailers and especially must be governed by the affiliate code of conduct. A good-faith offer should be responsive to the service requested. In other words, if a retailer only wants some services (e.g., billing) and not others (e.g., nonpayment risk coverage), an LDC should offer the unbundled service.

A final issue discussed concerned how to handle customer inquiries. There was general agreement that retailers should handle all inquiries concerning contract terms and commodity prices. There was also agreement that LDCs should handle inquiries pertaining to the wires portion of the bill, bill calculation errors and meter accuracy. There was no clear consensus regarding who should handle other types of inquiries, such as those concerning why a customer's usage may have gone up more than expected or how they might lower their energy costs. There was general agreement that customer's would expect to have such inquiries answered in a manner similar to current practice. However, whether such inquiries should be handled by an LDC or referred to a retailer was less clear. Some LDCs may wish to push such inquiries to retailers as a means of reducing costs. Other LDCs may wish to handle such inquiries as a means of maintaining customer satisfaction. Retailers will also differ in their interest in such inquiries. Those who are purely in the commodity business might be happy to have such inquiries handled by LDCs while those that also provide energy management services might wish to have such inquiries passed through the LDC to the retailer. At least one person suggested that this issue be left for market participants to work out while others felt that it should be dictated by the OEB. The group did not reach a consensus about this issue.

RECOMMENDATIONS:

1. LDCs must offer bill-ready consolidated billing to customers who are served by competitive electricity suppliers. LDCs are not required to offer rate-ready billing, but must make a good-faith offer to do so if asked.

2. Under bill-ready billing, a retailer will provide an LDC with the bill amount for the commodity and any additional retailer services and the LDC will post these amounts on a customer's bill, along with wires and other regulated charges. Up to two separate amounts will be received from retailers and posted by LDCs on each bill. These amounts must be provided to an LDC in sufficient time so that rendering a customer's bill is not significantly delayed beyond the LDC's normal bill-issue date. It is the retailer's responsibility to make arrangements with LDCs and/or other parties to obtain whatever information is required to calculate and provide the bill amounts in a timely manner. It is understood, however, that, in the absence of competitive meter services, LDCs will communicate customer usage data to retailers in a timely manner via electronic means. (See issues SG3-3 and SG3-4 for discussion of timing.) The assumption of customer nonpayment risk under this option is discussed under issue SG2-7.

3. Rate-ready billing or other billing services requested by a retailer over and above the minimum mandatory services outlined above must be offered on a good-faith basis. A good-faith effort is defined as making a non-discriminatory offer within a reasonable time frame for services requested by a retailer at a price that, at a minimum, fully recovers the cost of the additional services. If a retailer feels that an LDC is not negotiating in good faith, they can inform the OEB who will consider appropriate action.

4. Retailers must establish security arrangements with LDCs to cover retailer default risk during periods of time when the retailer's bill amount is expected to be less than the cost of supply based on the wholesale spot price. The magnitude of required coverage is defined in the recommendations for issues SG1-13.

5. LDCs will handle customer bill inquiries concerning the wires portion of the bill, meter accuracy, usage amounts and potential bill-calculation errors. For any inquiries about retailer pricing or contract terms, the customer will be referred to their retailer.

IMPLEMENTATION ISSUES:

Obligations of various parties associated with billing errors must be addressed. Also, timing data flaw between parties.

VOTER SUMMARY:

Five in favour; four against; one abstention.

DISSENTING OPINIONS:

The two retailer representatives at the meeting dissented from the majority opinion. In their view, the rate-ready options outlined above can be provided at reasonable cost (in conjunction with all of the other changes that must be made to billing systems) and would provide significant benefit to retailers entering the market. They believe that the rate-ready options outlined above should be mandatory. It should be mentioned that a subgroup representative from a competitive billing company agreed with the majority opinion and did not want the OEB to require that

LDCs offer rate-ready services that would compete directly with services offered by third-party billing companies. It should also be pointed out that retailers most likely will be able to make arrangements with billing companies that would allow them to receive most, if not all, of the benefits of rate-ready, LDC consolidated billing without having to construct their own billing system. This could be accomplished by contracting to a third-party billing company to calculate bills based on whatever price terms a retailer desires and then providing the bill-ready amounts to LDCs.

ISSUE STATEMENT: ***(Final)***

Issue SG2-5: Should a retailer that provides a consolidated bill have to pay the LDC for energy and wires costs even if they are not paid by the end-use customer being served?

OPTIONS:

1. LDCs must be paid for all services rendered to end-use customers through a retailer whether or not the retailer is paid by the end-use customer.

2. Retailers must pay LDCs for the energy portion of a bill regardless of payment from an end-use customer, but can pass through to LDCs nonpayment risk on the wires portion of the bill.

3. Customer nonpayment risk should be passed through to LDCs for the entire portion of the bill except for the retailer's gross margin on energy and wires services or for any non-electricity-related services (e.g., water heating, energy management, etc.).

BACKGROUND INFORMATION:

Although there was no formal recommendation by either the MDC or RTP on this issue, a general principle discussed in the Second Interim Report of the MDC, section 4.3.10, is that a competitive retailer that bills on behalf of an LDC should assume the responsibility for nonpayment risk by end-use customers. That is, an LDC should get paid regardless of whether or not the retailer gets paid. This is the established rule in most other jurisdictions that we are familiar with, including California.

If retailers are not held responsible, they would be allowed to hold back payment to LDCs for services rendered if not paid by the customer. LDCs could then begin collection actions.

There is no guidance on this issue from the gas industry because the unbundling of the billing function, which would make consolidated retailer billing a practical option, is not yet in place.

Historically, bad debts by LDCs in Ontario are in the range of .1 of 1 percent. This low percentage is believed to result from several factors, including the threat (and use) of disconnection and the historic right of MEUs to place tax liens on property as a means of collecting past-due bills. It may also result from close monitoring of customer accounts, the widespread use of deposits for customers who lease property, proactive practices by LDCs in working with customers to establish reasonable payment terms and the use of equal billing plans to avoid cash flow problems during high use months.

As discussed below, an important consideration surrounding this issue is the legal prohibition on retailers ordering disconnection of customers for nonpayment. Section 31(1) of the *Electricity Act, 1998* states, "A distributor may shut off the distribution of electricity to a property if any amount payable by a person for the distribution or retail of electricity to the property pursuant to section 29 is overdue." (Note: Section 29 refers to SSS.)

SUMMARY OF GROUP DISCUSSION:

All parties agree that nonpayment risk is a normal cost of doing business. However, because of legal constraints on disconnection imposed by the *Electricity Act*, not all parties have access to the same risk mitigation procedures in the restructured electricity market. Specifically, retailers are not allowed to order disconnection by an LDC for nonpayment of retailer bills. Disconnection is only allowed for nonpayment of distribution or SSS to LDCs. Consequently, if a retailer offers consolidated billing and is not paid, they can drop a customer but have little leverage to recover payment for services already rendered. LDCs who offer consolidated billing, on the other hand, can use the threat of disconnection and the withholding of reconnection pending payment as a means of mitigating nonpayment risk.

The subgroup discussed the advantages and disadvantages of allowing retailers to pass-through some or all of the nonpayment risk as a means of transferring the threat of disconnection through to end-use customers even when retailers offer consolidated billing. An inquiry to staff at the Ministry of Energy indicated that this solution would not be viewed to be in violation of the act. Retailers were in favour of this option and were very concerned about the potential increase in nonpayment risk if the threat of disconnection is lost. Retailers felt that they could live with the historically low bad debt percentage enjoyed in the province, but worried that bad debt could increase significantly once customers realised that the consequences of defaulting on retailer payments were not grave (e.g., they simply revert to SSS and keep receiving electrons).

LDCs were sympathetic to retailer concerns but were also very concerned about an increase in bad debt resulting from a loss of direct communication and connection to customers when retailers provide consolidated billing. LDC representatives argued that they often identify potential bad debt customers early, monitor them closely and work with them to avoid nonpayment and disconnection. They fear the loss of this ability. Some LDC representatives indicated that they would be open to option 2 or 3 only if retailers were forced to implement stringent collection procedures and monitoring similar to the current practices of LDCs. LDCs also pointed out that if split billing and LDC consolidated billing are available to retailers, they can mitigate risk by selecting one of these other options.

Most, if not all, subgroup members felt that options 2 and 3 were an attempt to get around restrictions in the *Electricity Act* that probably shouldn’t have been there in the first place. In other words, this wouldn’t be an issue if retailers had the right to order disconnection for nonpayment for services rendered in the same manner that LDCs do.

RECOMMENDATIONS:

In the event that a retailer offers full consolidated billing, the retailer must pay LDCs for energy and wires charges attributable to the end-use customers they serve regardless of whether or not the retailer is paid by the end-use customer. That is, the retailer must assume the customer nonpayment risk for all charges billed under this billing option.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Sixteen in favour of the recommendation, all LDCs; four against the recommendation, all retailers.

DISSENTING OPINIONS:

Retailer representatives recommended that retailers be allowed to transfer nonpayment risk for wires charges through to LDCs in order to gain the threat of disconnection. In response to these concerns, the subgroup developed an alternative billing-option proposal, partial consolidated billing, which is discussed on the following pages.

ISSUE STATEMENT: ***(Final)***

Issue SG2-6: In the event that a split-bill option is offered, which parties should be responsible for customer nonpayment risk?

OPTIONS:

1. LDCs to be accountable for nonpayment for all services.

2. LDCs and retailers to be accountable for nonpayment for the services each provides.

3. Retailers to be accountable for nonpayment for all services.

BACKGROUND INFORMATION:

Bill 35 states that a service cannot be terminated for nonpayment of a retailer's bill, but only for nonpayment of default supply. Retailers will be able to terminate contracts with customers when there is nonpayment.

The gas industry does not have a split-bill option, although historically it hasn't been an issue because only gas LDCs could bill for services.

SUMMARY OF GROUP DISCUSSION:

- Retailers were not present at the first meeting where this was discussed but were present at the second subgroup meeting and at the Task Force review.

- Option 3 was not discussed.

- Option 1 and 2 were discussed at length.

- LDCs support the disconnection of customers for nonpayment of services they provide.

- Neither LDCs nor retailers want to be held responsible for nonpayment of services they do not provide.

RECOMMENDATIONS:

With split billing, retailers should only be responsible for customer nonpayment of services they provide, not for the wires services being billed separately by LDCs to end-use customers. That is, each party assumes nonpayment risk for the services for which they bill.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG2-7: Who should assume customer nonpayment risk where an LDC provides a consolidated bill?

OPTIONS:

1. The LDC could assume the risk and the retailer would not be responsible for the nonpayment of an account by an end-use customer. The retailer would therefore receive full payment for the commodity without deduction for any bad debts.

2. The LDC could initially absorb the loss due to nonpayment by the end-use customer but recover the actual bad debt from the retailer (commodity only).

3. The LDC could initially absorb the loss due to nonpayment by the end-use customer but recover the approximate bad debt from the retailer by including an allowance for bad debts in the service fee charged to the retailer for billing and collecting services.

4. The industry (government?) could set up a provincial clearinghouse for bad debts associated with electricity distribution and supply which would be funded from a share of gross revenues from all LDCs and retailers in order to facilitate social programs that provide free electricity to targeted groups or customers. (This apparently exists in a few US jurisdictions with resulting bad debt losses in the range of 6 to 8 percent.)

5. Who assumes nonpayment risk should be negotiated on a good-faith basis between retailers and LDCs under the assumption that there would be no cross-subsidisation of such services by standard supply customers.

BACKGROUND INFORMATION:

Many LDCs in Ontario experience bad debts in the range of $^{1}/_{10}$ percent due to the use of risk mitigation procedures such as the use of security deposits, the threat of service disconnection and the ability to place liens on property in the event of customer nonpayment. Other LDCs experience higher collections risk, in the range of 2 to 5 percent among mass-market customers. With corporatisation (which eliminates the ability of MEUs to place liens for nonpayment) and other changes in the market, there is general agreement that the collections problem may increase, perhaps significantly.

Under the new legislation, LDCs retain the right to disconnect service for nonpayment. However this privilege is not extended to retailers, who can neither disconnect a customer nor order an LDC to do so. However, when an LDC issues a consolidated bill, it may disconnect for nonpayment of the bill or for partial nonpayment if the nonpayment portion is attributed to the wires portion of the bill. To the extent that the threat of disconnection helps reduce nonpayment risk, retailers may wish to enjoy this low bad debt performance by paying LDCs to issue consolidated bills rather than issue their own consolidated bill and loose the risk mitigation procedure of service disconnection. If this is the case then there is still an issue regarding who should absorb the residual bad debts.

The Gas Industry has a practice similar to option 3 above, where the retailer is charged an estimated amount for their share of bad debts. This charge is included in the fee charged by a gas distributor to a gas retailer for accounting, billing, collecting and transmission services.

SUMMARY OF GROUP DISCUSSION:

It was understood by subgroup 2 participants that LDCs were to largely be protected from risk which was interpreted to mean that LDCs were not obligated to absorb bad debt losses associated with a retailer's commodity charge and were entitled to use various risk mitigating procedures to secure all accounts. It followed therefore that options 1 and 5 above were rejected and more attention was focussed on options 2, 3 and 4 which provided for the recovery of bad debt losses (for the commodity) from the retailer. The LDC would still be responsible for bad debts associated with the wires charges.

In considering the merits of recovering the exact commodity bad debt from a retailer or recovering an estimated amount for bad debts as a part of the billing and collecting charge to the retailer, it was noted that the gas industry favours the second practise.

Given the simplicity of including a reasonable allowance for bad debts in the billing and collecting charge to a retailer and considering that this practise would be an incentive to LDCs to continue to do a good job in collecting (because they may be able to keep the difference between the actual bad debt and the allowance paid by the retailer), the group generally favoured option 3. However, some LDC participants worried that it will be difficult, at least initially, to accurately predict the magnitude of bad debts in light of all of the changes that are occurring in the market and the general agreement that bad debt overall is likely to increase. These participants favoured the voluntary provision of option 3 with option 2 being the default.

RECOMMENDATIONS:

1. In the event that a retailer elects consolidated billing by an LDC, the LDC must offer to assume customer nonpayment risk for bill amounts associated with the full cost of delivered electricity. LDCs need not assume risk for any non-electricity-related services that might be included in a retailer's bill (e.g., home security, demand-side management services, etc.). The fee for this service will be based on an OEB approved rate. In the event that bad debt costs exceed the amount of money collected through the OEB-approved tariff, an LDC's shareholders will absorb the incremental cost. In the event that bad debt costs are less than the amount collected through the tariff, an LDC's shareholders will reap the benefit. LDCs may use whatever means are available under the law to mitigate customer nonpayment risk, including the threat of or implementation of disconnection for nonpayment of wires charges.

2. Retailers may or may not accept the offer outlined in recommendation 1. In this event, an LDC must pass through the bad debt costs and the cost of reasonably incurred collections procedures through to the retailer (e.g., operate under option 2 outlined in the options section

above). That is, a retailer must pay an LDC for the costs associated with provision of the commodity even if the customer does not pay for the commodity.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Nineteen in favour; one against (LDC).

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG2-8: Risk mitigation procedures.

- What risk mitigation procedures should be available to LDCs and should they be equally available to retailers?
- Should the Retail Settlement Code provide an exhaustive list of risk mitigation procedures or should the LDCs be free to choose whatever method they wish?

OPTIONS:

1. LDCs could be limited to a predefined list of risk mitigation procedures.
2. LDCs could be unrestricted in their use of risk mitigation procedures unless otherwise noted in the *Electricity Act*.
3. Retailers could be given the same predefined list of risk mitigation procedures as set out for LDCs.
4. Retailers could be restricted to adhere to a predefined list of risk mitigation procedures that are unique to retailers.
5. Retailers could be unrestricted in their use of risk mitigation procedures unless otherwise noted in the *Electricity Act*.
6. A list of approved risk mitigation procedures would be referenced within the Retail Settlement Code.
7. No specific list of risk mitigation procedures would be referenced within the Retail Settlement Code and LDCs would be free to choose their own procedures unless otherwise noted in the *Electricity Act*.

BACKGROUND INFORMATION:

Both LDCs and retailers have various tools at their disposal to mitigate nonpayment risk by end-use customers. These include deposits, late payment charges, the threat of disconnection (for LDCs only), prepayment, prepaid meters, load limiters and insurance. A useful discussion is contained in section 6.3 of the Retail Technical Panel Report. The only Retail Technical Panel recommendation on this issue (R6-11) is that LDCs should be allowed to use any tools they deem appropriate to mitigate end-use customer nonpayment risk.

SUMMARY OF GROUP DISCUSSION:

Subpanel participants agreed that unless otherwise indicated within the *Electricity Act*, LDCs and retailers should be equally free to choose whatever risk mitigation procedures they wish and that the development of an exhaustive list of mitigation procedures is not deemed appropriate or prudent.

RECOMMENDATIONS:

LDCs and retailers will be free to use any risk mitigation strategies allowed under the law.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATMENT: ***(Final)***

Issue SG2-9: What should happen to a customer's deposit when a customer switches:

- From an LDC to a retailer?
- From one retailer to another?
- From a retailer back to an LDC?

OPTIONS:

1. Deposit is returned to the customer.
2. Deposit travels from one supplier to another.
3. Where there may be a "wires" deposit and a "supply" deposit, one deposit may travel from one supplier to another.
4. LDCs hold all customer deposits with explicit rules established to direct payment to the appropriate party in the event of a customer's default.

BACKGROUND INFORMATION:

The RTP (6-11) recommends that distributors be allowed to use strategies such as deposits, late payment charges and prepayment for customers that distributors are obligated to supply. It did not specifically address deposit transfer issues.

This recommendation reflects current electrical industry practices whereby LDCs return deposits upon closing an account.

SUMMARY OF GROUP DISCUSSION:

- Whoever is responsible to collect payments when rendering consolidated billing to end-use customers should hold the deposit.
- Whoever is financially liable for incurring losses due to nonpayment by end-use customers should retain the deposit and manage risk mitigation.
- The party rendering consolidated billing is also assuming payment risks, hence to reduce potential losses, responsible party shall retain and manage deposit for these customers.
- Under split-billing arrangements LDCs may retain the full amount of the existing deposit OR return to the customer the portion of the deposit amount equivalent to "supply/ consumption" charges.

- When LDCs or retailers are involved in split-billing arrangements, deposit values should reflect the level of risk that is associated with the service being provided.

RECOMMENDATIONS:

If an LDC holds a customer deposit when a customer changes suppliers and the new supplier is offering consolidated billing, the deposit should be applied to the final bill. Any remaining amount should be returned to the customer according to the terms specified by the LDC when the deposit was collected. LDCs have no obligation to redirect any portion of a deposit to a retailer. In the event that split billing is chosen by a customer or retailer, deposit amounts held by LDCs should be adjusted in accordance with the risk associated with the new level of service provision (e.g., commensurate with the estimated amount of the wires charge only).

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Unanimous; 20 in favour.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: *(Final)*

Issue SG2-10: Should an LDC be allowed to refuse to reconnect a customer unless the customer has paid all past due bills associated with wires charges and standard supply?

OPTIONS:

1. An LDC can refuse to reconnect a customer until the terms of disconnection have been met, whether or not a retailer has now agreed to provide service to the customer.

2. An LDC can refuse to reconnect a customer based on its terms of service. It cannot refuse to connect a customer based on a retailer request. In other words, even if a customer has not fully paid an LDC for past services, if a retailer agrees to serve the customer in the future, the LDC must reconnect the customer.

BACKGROUND INFORMATION:

- Subsection 31(1) of the *Electricity Act* states, "A distributor may shut off the distribution of electricity to a property if any amount payable by a person for the distribution or retail of electricity to the property pursuant to section 29 is overdue."

- OEB staff interpretation; retailers may not disconnect customers for nonpayment of competitive services.

- RTP R6-10 states that LDCs should be allowed to refuse to reconnect unless a customer has paid all past due bills associated with wires charges and standard supply.

- (Current guideline) Standard Application of Rates; if the bill is still unpaid 16 calendar days after the due date and seven calendar days after a disconnect notice has been given to the customer, the service may be discontinued and not restored until satisfactory payment arrangements have been made. Such discontinuance of service does not relieve the customer of the liability for arrears or minimum bills for the balance of the term of contract nor shall the Supply Authority be liable for any damage on the customer's premise resulting from such discontinuance of service. Disconnect notices will be in writing and if given by mail shall be deemed to be received on the third business day after mailing.

- (Current guideline) Municipal Electric Association Administrative Practices; if an account is unpaid seven days after the due date, the utility may deliver a notice of disconnection in writing by mail or delivery. Landlords and/or tenants of the customer on request may receive notice of disconnection in a similar manner. Service may be disconnected seven days after delivery of the disconnect notice. There must be reasonable effort to communicate directly to the occupants and/or owners.

- Municipalities may enact a vital services bylaw which permits a municipal official to enter into an agreement with the utility on behalf of the municipality to ensure vital services are provided to rented or leased premises. The bylaw would ensure that the utilities are paid either by the landlord or the municipality. The bylaw has the effect of removing the utility from having to disconnect residential tenants whose utilities are included in their rent.

- (Current Guideline) *The Public Utilities Act* provides that in default of payment the corporation may shut off the supply but the rents or rates are recoverable. Also the utility has the right to access to discontinue service.

- *The Bankruptcy and Insolvency Act* contains specific sections with respect to service supply particularly where the debtor has filed a proposal.

- *The Companies' Creditors Arrangement Act* contains specific sections with respect to payment and service supply rights.

SUMMARY OF GROUP DISCUSSION:

- The customer may be an owner or tenant. Only the customer who had a supply arrangement with the utility and has defaulted can be refused service. Payment default is customer specific, not service specific. Thus, if a customer has defaulted at one location he can be refused reconnection at another location.

- Current guidelines are workable.

- Local conditions and requirements may be taken into consideration.

- Historically, utilities have made arrangements with customers that are satisfactory and within the utility guidelines for arrears of active accounts and disconnected accounts that are still active or have been finalised.

- Utilities may have guidelines or policies with respect to disconnection, payments arrangements and reconnection.

- Retailers cannot disconnect or reconnect but they may terminate their contract with the customer for supply.

- Load limiters, service interrupters and prepaid meters are tools that may be used by a utility for accounts that are in arrears. For purposes of reconnection and disconnection when these devices are used it is assumed that there is no permanent disconnection of service as the customer still has the ability to maintain service supply.

RECOMMENDATIONS:

LDCs must "retain the right" to refuse to reconnect until all arrears are paid in full to the LDC for distribution or SSS.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG2-11: What guidelines should be set for the timing and notification of disconnection?

OPTIONS:

1. LDCs should be allowed complete discretion in this area subject to the specific guidelines identified in the *Electricity Act.*

2. Uniform, detailed guidelines should be established and used throughout the province.

BACKGROUND INFORMATION:

See the detailed listing of relevant statutes and practices provided under the discussion for issue SG2-10.

Section 31(2) of the *Electricity Act, 1998* states, "A distributor shall provide reasonable notice of the proposed shut off to the person who is responsible for the overdue amount by personal service or prepaid mail or by posting the notice on the property in a conspicuous place."

SUMMARY OF GROUP DISCUSSION:

- The customer may be an owner or tenant.
- Current guidelines are workable.
- Local conditions and requirements may be taken into consideration.
- Historically utilities have made arrangements with the customer that are satisfactory and within the utility guidelines for arrears on active accounts and disconnected accounts that are still active or have been finalised.
- Utilities may have guidelines or policies with respect to disconnection, payments arrangements and reconnection that use the guidelines as minimum.
- Subgroup participants saw no major advantage to uniformity from the perspective of supporting the competitive market or hindering retailer supply and agreed that local population characteristics and conditions vary, making flexibility a virtue.

RECOMMENDATIONS:

Present LDC disconnection practices may continue provided they do not contravene the *Electricity Act*.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

ISSUE STATEMENT: ***(Final)***

Issue SG2-12:

- What costs should be shown on a settlement invoice to a retailer?
  - Individual customer data?
  - Retailer administration fees (switching, special meter reads, consolidated billing fees)?
- Does the retailer invoice reflect the unbundled bill format?
- How does the invoice change with billing options?
- When should a retailer be invoiced for the various charges?

OPTIONS:

1. Costs shown on a settlement invoice to a retailer:

   (a) Regardless of billing option retailer will receive same line items as SSS bill for end-use customers with a summary (total) of net amount owed to LDC by line item. Administration fees will be itemised by account number and type and totalled by type (e.g., meter charges, special meter reads, billing fees, set-up charges, etc.)

   (b) In the case of retailer consolidated billing, the retailer would receive the same line items as the SSS bill for end-use customers. In the split-bill scenario the retailer would receive only the SSS commodity line items. In the "LDC consolidated billing" the retailer would receive only the net SSS commodity line items. Administration fees will be itemised by account number and type and totalled by type (e.g., meter charges, special meter reads, billing fees, set-up charges, etc.)

2. When a retailer should be invoiced for the various charges:

   (a) Invoice by bill group/cycle for end-use customers and a separate monthly for administration fees.

   (b) Invoice by bill group/cycle for end-use customers and add administration fees as separate line items to one bill a month.

   (c) Invoice by bill group/cycle for both end-use customers and administration fees incurred that day plus a prorated portion of monthly service charges such as rate changes, billing fees and other discretionary and non-discretionary fees.

BACKGROUND INFORMATION:

It is assumed that retailers will want to see individual customer data and that the only reasonable means of providing this information is in an electronic format. In the event that a retailer exercises more than one billing option it will be more cost effective for a LDC to provide the same information for end-use customers regardless of billing option. While LDCs could customise the information sent to retailers based on the bill option, SSS customers should not bear the inevitable increased costs for these customised invoicing services. Retailers who benefit from the customisation should bear this cost if LDCs decide to invest in providing the service for business reasons.

The daily summary of the end-use customers billed that day will provide the net total owed to the LDC by line item and it is expected that this will be included in one electronic file.

The administration charges such as switching, billing, bill set-up, rate change, meter changes, special meter reads, etc. are more conveniently billed on a monthly basis as they may not be incurred on the same billing cycle/date as the commodity and wires charges. For example, if a retailer may implement new rates while exercising an "LDC bills all billing option," administration charges will be charges to the retailer for the programming costs to change the rates in the billing system. These charges would be a one-time charge and not relate to individual end-use customer bills. Monthly billing of administration charges may also provide a clearer audit trail.

SUMMARY OF GROUP DISCUSSION:

One of the underlying assumptions around LDC billing to retailers is that invoices will be transmitted electronically utilising the provincial EBT systems as developed under the recommendations provided by subgroup 4.

Further, the group agreed that bills should be itemised by individual account number and totalled by cost category.

There was significant discussion around the level of detail required to be shown. In general, retailers felt that LDCs should provide the level of detail that was required to calculate the SSS bill for each end-use customer. LDCs were concerned that this level of detailed information may not reside in a single information system and would have to be pulled from multiple systems and consolidated for the benefit of the retailer, thus creating added costs.

There appeared to be general support for the argument that retailers should have access to the same level of detailed information as was passed from the settlements system to the billing system for calculation and presentment of SSS customer bills.

Discussion ranged on the details that would be required. To date LDCs are unsure of the level of unbundling that will be mandated at open access, however, the general impression is that at a minimum, the following items will be displayed as separate line items on customer bills:

- Competitive electricity charge (cost per kWh).

- Transmission charge (with fixed, energy and demand components).
- Distribution charge (with fixed, energy and demand components).
- Competition Transition Charge (uncertain how this would be allocated).
- Market Power Mitigation Credit (uncertain how this would be allocated).
- G.S.T. for each of the above components.
- Avoided cost credits (for meter reading, meter service and billing service).

The group agreed that it was premature to explicitly state what level of detail would be required on the retailer invoice, when it is unknown what level of detail will be required on the SSS bill. [Question: Is one of the codes or the PBR handbook going to deal with this????]

RECOMMENDATIONS:

Costs shown on a settlement invoice to a retailer:

> Regardless of billing option, retailers will receive at a minimum, the unbundled bill determinants that the LDC would use to calculate the SSS bill for each end-use customers served by that retailer. This information is deemed to be, at a minimum, the items listed above. In addition, a summary and total of all charges will also be provided. Administration fees will be itemised by account number and type and totalled by type (e.g., meter charges, special meter reads, billing fees, set-up charges, etc.)

When a retailer should be invoiced for the various charges:

> Invoice by bill group/cycle (could be daily, weekly or some other frequency depending on LDC billing schedules) for end-use customer-related charges. Invoices including end-use customer data would be provided in an electronic format via the provincial EBT system. A separate monthly invoice for administration fees may be issued (not using EBT at the start of the market).

IMPLEMENTATION ISSUES:

Direction is needed from (OEB) regarding the minimum mandated unbundling required for SSS customer bills in order to determine the level of detail that can be passed on to retailers in their invoicing.

VOTER SUMMARY:

The vote at the Task Force meeting of October 5, 1999 was unanimous on both parts I and II.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG2-13: Should the timeline for settlement invoicing between LDCs and retailers be mandated under the code for each of the different bill options, i.e., split bills, LDC and retailer consolidated billing?

OPTIONS:

1. Make reference in the code that service agreements between LDCs and retailers must at a minimum, specify a settlements timeline that parallels the timeline for settlement between an LDC and its SSS customers, regardless of the bill option. Any other timeline could be the subject of negotiations between an LDC and retailer, but LDCs would not be obligated to support these and may charge for services beyond the minimum standard.

2. Mandate the specifics of the settlements invoicing timeline in the code for each of the bill options, i.e., split bills, LDC and retailer consolidated billing.

3. Make reference in the code that service agreements between LDCs and retailers must identify the schedule/critical dates in the settlement timeline negotiated between the parties for each of the bill options.

BACKGROUND INFORMATION:

There are a number of critical dates and activities in the settlement timeline for electricity delivery and supply. Key milestones include meter read dates, bill issue dates, due dates, remittance dates and collection dates. Key activities include reading or estimating of meters, conversion of meter read data into VEE billing quantities, determination of pricing data, calculation of charges and formatting of the bill data for presentment.

Further complicating these dates and activities is the requirement to be able to make adjustments to bill data in both the pre-bill and post-bill stages as errors and exceptions are identified. An example of a pre-bill error/exception would be an out-of-range meter reading, an example of a post-bill error/exception would be an incorrect meter reading or bad estimate identified by the customer on receipt of the bill.

At market opening, these processes and timelines become much more complex for two reasons: (a) the introduction of multiple new parties in the billing/settlements process who will be sending and receiving information in order to generate bills; and (b) the requirement for LDCs to calculate an SSS service bill, based on the wholesale spot price for electricity, for every customer connected to their wires—and direct the appropriate charges to either the end-use customer or the retailer supplying the customer.

Market opening will introduce a ten business day lag between the trade (or read) day and the availability of preliminary pricing data from the IMO on which LDCs must calculate the NSLS/weighted average cost of power to be utilised for billing cumulative metered customers. Meter data will be made available to authorised retailers, likely through a Meter Data Mart. For interval metered customers the lag between read date and the cut-off for posting VEE quantities is expected to be ten business days, while non-interval meter data may be available as early as the night of reading. Retailers would be responsible for accessing this data once it is made available if they are responsible for calculating a portion or all of a customer's bill.

Ultimate responsibility for payment of the SSS bill items is dependent on whether the customer is being supplied by a competitive retailer or not and the bill option under which they are being supplied.

Many if not most LDCs bill their customers based on cycles or groups in order to bring cost and work management efficiencies to the meter reading and billing processes. These efficiencies would be severely strained if the billing/settlements timeline for customers within a cycle or group varied between SSS and retailer-supplied customers and by bill option. While it is not impossible for LDCs to produce bills off cycle, standard supply customers should not bear the inevitable added costs that off-cycle services would create. Retailers who benefit from such services should bear these costs if LDCs decide to invest in them for business reasons.

Other LDC concerns would be around managing many different billing schedules, lack of consistency between customers in the same bill cycle or group and resulting confusion, unnecessarily increased complexity in an already complicated environment.

In a split-bill scenario, the LDC would likely prefer to calculate all charges at once and direct them to the appropriate party (end-use customer or retailer) at the same time.

For an LDC bills all scenario, the preference would be to receive the retailer bill-ready data within the ten business day window between the meter read and IMO pricing availability so that both the customer bill and the retailer settlement bill can be calculated at the same point in time. If retailers' bill-ready data missed the billing window, then it would need to be resubmitted by the retailer for presentment on the subsequent bill.

Where the retailer bills all, the retailer would be free to bill on any timeline, but would not receive LDC bill-ready wires charges until after the ten-business-day lag.

Conceptually, the timeline and milestones might look as follows:

Day (business days)

n Trade day/meter-read day

n + 4 All non-interval meter read VEE data posted and accessible

n + 10 All interval meter read VEE data posted and accessible

LDCs receive IMO preliminary pricing data.

LDCs calculate NSLS and WACOP for billing SSS.

Cut-off for LDC receipt of retailer bill-ready line items.

n + 11 LDC calculates and produces SSS bills to end-use customers

LDC calculates and produces retailer settlement bills.

LDC calculates and produces split bills.

LDC calculates and produces LDC consolidated bills.

LDC calculates and sends bill-ready wires charges to retailer for retailer bills all.

The above assumes electronic transfer of bill data between LDCs and retailers, using the provincial EBT system and allows retailers to retrieve meter data, do their commodity calculations and pass bill-ready line items back to LDCs during the period between *n* and *n* + 10 business days.

At *n* + 11 business days, the LDC would simultaneously bill their SSS end-use customers and retailers.

SUMMARY OF GROUP DISCUSSION:

There was considerable discussion around the settlements timeline and the cash flow implications for retailers and LDCs due to the ten-business-day lag from meter reading to availability of pricing data from IMO.

While it was recognised that under certain bill options, customer billing and settlement invoice timelines were not inextricably tied, the consensus of opinion was that there would be both cost and administrative efficiencies gained from LDCs simultaneously billing their SSS end-use customers, LDC consolidated billing and retailer settlement invoicing.

RECOMMENDATIONS:

Option 1 is recommended. Make reference in the code that service agreements between LDCs and retailers must at a minimum, specify a settlements timeline that parallels the timeline for settlement between an LDC and its SSS customers, regardless of the bill option. Any other timeline could be the subject of negotiations between an LDC and retailer, but LDCs would not be obligated to support these and may charge for any services beyond the minimum standard.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

APPENDIX C

Subgroup 3: Retail Settlement Calculations and Information Development

ISSUES LIST

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2. Issue SG3-2: Incorporating IMO non-commodity charges into settlement calculations C-9
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21. Issue SG3-21: Calculating customer commodity bills with market power mitigation rebate C-76

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24. Issue SG3-24: Embedded retail generators C-85

25. Issue SG3-25: Embedded retail generation settlement C-88

26. Issue SG3-26: Retail settlement calculations for LDC charges C-92

ISSUE STATEMENT: ***(Final)***

Issue SG3-1:

- 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.

(Note: When incorporating these recommendations and related ones into the Code, there was a change in terminology from "commodity costs" to "competitive electricity costs.")

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.

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	Comments
1. Hourly Energy Settlement Amounts by Registered Facility	3									
2. Physical Bilateral Congestion Management Charge	3									Charge to capture the price differences between supply and delivery points
3. Hourly uplift	3									May eventually include must-run contracts uplift. Uplifts listed here are as they appear in Market Rules.
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									Created by difference in scheduled and actual flows at interties.
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						

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	Comments
7. Transmission Rights Auction Revenues			2		2	2				Details not resolved.
8. Market Participant Default Charge		2								If an MP defaults, the amount will be recaptured from MPs based on load.
9. Outage Cancellation/Deferral Uplift	2	2								To compensate generators for deferred or cancelled outages.
10. Market Suspension Additional Compensation Uplift	2	2								If a generator is not adequately compensated by admin. Price, additional compensation will be paid and recouped from MPs based on load.
11. IMO Administration Charge	2	2								This administration charge is the IMO tariff which will be set annually, allocated hourly and most likely settled monthly
12. IMO Transaction Fees						3				
13. IMO Registration Fee									3	
14. IMO Penalties						3				Penalty schedule will be published annually. Penalties will be assessed when violations occur.
15. Competition Transition Charge	2	3								Details not resolved.
16. Rural Rate Protection		3								Details not resolved.
17. Market Power Mitigation		3								Details not resolved.
18. Basic Use Service Charge			2	2						Details not resolved.
19. Pooled Connection Service Charge			2	2						Details not resolved.
20. Pooled Transformation Service Charge			2	2						Details not resolved.
21. Wholesale Meter Pool Charges					2					Details not resolved.

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)***

Issue SG3-2: How should non-commodity charges from the IMO be incorporated into settlement calculations? *(Note: When incorporating these recommendations into the Code, there was a change in terminology from "non-commodity IMO charges" to "charges for non-competitive electricity services.")*

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: ***(Final)***

Issue SG3-3: 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 SG3-5. 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:

   (a) LDC customer account number.

   (b) LDC meter number.

   (c) Service address.

   (d) Date of most recent meter read.

   (e) Date of previous meter read.

   (f) kWhs recorded at time of most recent meter read.

   (g) kWhs recorded at time of previous meter read.

   (h) Multiplied kW for the billing period (if demand metered).

   (i) Multiplied kVa for the billing period (if available).

(j) Usage for each hour during the billing period for interval-metered customers.

(k) 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:

7. 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.

8. 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.

9. 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.

10. 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: ***(Final)***

Issue SG3-4: 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 SG1-6, 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 SG3-3 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 retailers serve a large number of customers, 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 SG3-3) 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: ***(Final)***

Issue SG3-5: 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 MDMAs 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 MDMAs 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:

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 MDMAs 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 MDMAs, 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. MDMAs 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, MDMAs 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 MDMAs 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 MDMAs to compete in the non-remotely read meters market. This is because the alternative would make it very difficult for MDMAs to optimise the efficiency of meter reading since they would not have the flexibility to establish their own meter-reading routes. Allowing MDMAs 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, MDMAs 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. MDMAs 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 fourth business day after Sunday, 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 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 9, issue SG3-3, 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 specified.

ISSUE STATEMENT: ***(Final)***

Issue SG3-6: 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 MDMAs. 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

[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, pages 1-6 through 1-13.

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.

– 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]

[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

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.
- 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 MDMAs 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 MDMAs 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

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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.

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 MDMAs should be liable for billing errors, if an entity is unable to collect, argue that

- This approach is more consistent with recommendation 4-25 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 loose 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)***

Issue SG3-7: 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:

1. Utilise final verified data from the IMO with full loss reconciliation.
2. Utilise final verified data from the IMO without loss reconciliation.
3. Utilise preliminary statement data from IMO without loss reconciliation.
4. Utilise unverified wholesale and retail interval meter data and "six-day" wholesale price data.
5. 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 recommendation 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 SG3-14 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.

RECOMMENDATIONS:

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. 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.

DISSENTING OPINIONS:

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.

ISSUE STATEMENT: ***(Final)***

Issue SG3-8: 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.

SUMMARY OF 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
Single and Zonal Monthly Spot Price Comparison

Spot Price	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ZONE 1	$ 28.26	$ 22.06	$ 28.67	$ 32.00	$ 33.88	$ 44.86	$ 31.21	$ 35.45	$ 38.08	$ 50.40	$ 35.52	$ 34.85
ZONE 2	$ 28.15	$ 22.02	$ 28.72	$ 32.19	$ 34.36	$ 45.93	$ 31.46	$ 36.06	$ 38.54	$ 50.66	$ 35.73	$ 34.82
ZONE 3	$ 28.15	$ 21.99	$ 28.81	$ 32.08	$ 34.53	$ 45.41	$ 31.41	$ 35.90	$ 38.79	$ 50.96	$ 35.86	$ 35.34
ZONE 4	$ 27.87	$ 21.87	$ 28.86	$ 31.82	$ 34.42	$ 43.46	$ 30.58	$ 34.97	$ 38.05	$ 50.22	$ 35.52	$ 35.16
ZONE 5	$ 26.33	$ 22.01	$ 28.90	$ 32.12	$ 34.52	$ 45.59	$ 30.88	$ 35.53	$ 38.57	$ 51.24	$ 36.05	$ 35.39
ZONE 6	$ 27.91	$ 21.98	$ 28.85	$ 32.00	$ 34.32	$ 45.06	$ 30.87	$ 35.61	$ 38.54	$ 51.01	$ 35.82	$ 35.24
ZONE 7	$ 28.24	$ 22.00	$ 28.92	$ 32.10	$ 34.27	$ 45.46	$ 30.73	$ 35.94	$ 38.46	$ 50.82	$ 35.80	$ 35.23
ZONE 8	$ 28.38	$ 22.11	$ 29.00	$ 32.25	$ 34.30	$ 45.79	$ 31.10	$ 36.00	$ 38.22	$ 50.66	$ 35.84	$ 35.06
SINGLE ZONE	$ 27.91	$ 22.01	$ 28.89	$ 32.10	$ 34.35	$ 45.40	$ 30.98	$ 35.78	$ 38.41	$ 50.81	$ 35.82	$ 35.18

Spot Price	Average	% from SZ Price	% of SZ NSLS	RIM Load in Zone
ZONE 1	$ 34.20	-0.61%	4.02%	16.28%
ZONE 2	$ 34.24	-0.50%	6.02%	8.47%
ZONE 3	$ 34.24	-0.49%	5.93%	6.13%
ZONE 4	$ 33.83	-1.70%	7.93%	9.60%
ZONE 5	$ 34.23	-0.53%	14.70%	4.82%
ZONE 6	$ 34.13	-0.83%	15.68%	4.88%
ZONE 7	$ 34.54	0.38%	20.05%	2.32%
ZONE 8	$ 34.88	1.36%	25.54%	2.54%
SINGLE ZONE	$ 34.41			

1. Monthly Spot Price calculation is based on 98 Alberta Pool price and zonal/overall load data.
2. "Average" is weighted average value based on each zone's monthly MWh load.
3. "% from SZ" is the difference between zonal price and Single Zone (SZ) price, expressed as a % of Single Zone price.
4. "% of SZ NSLS" is the zonal annual kWh as a % of total (single zone) annual kWh.

Table 2
Annual Billing Difference Between Single & Multiple Zone Settlement Using RTP II and Adjusted PJM & Alberta Hourly Price

	Annual kWh	Annual Bill Based on RTP II - Single Zone	Multi-Zone Difference	Annual Bill Based on PJM -Single Zone	Multi-Zone Difference	Annual Bill Based on Alberta - Single Zone	Multi-Zone Difference
ZONE 1 CUSTOMER 1	15,800	$ 609.82	$ 4.33	$ 601.29	$ 9.59	$ 630.97	$ 3.89
ZONE 1 CUSTOMER 2	8,960	$ 356.75	$ 2.78	$ 356.42	$ 6.15	$ 352.15	$ 1.67
ZONE 2 CUSTOMER 1	20,970	$ 811.63	$ 1.52	$ 794.50	$ 8.12	$ 804.34	$ (0.90)
ZONE 2 CUSTOMER 2	15,520	$ 609.14	$ 0.91	$ 621.85	$ 5.86	$ 618.00	$ (1.04)
ZONE 3 CUSTOMER 1	15,790	$ 617.88	$ 0.20	$ 612.24	$ 2.99	$ 626.60	$ (2.22)
ZONE 3 CUSTOMER 2	13,350	$ 531.44	$ 0.06	$ 557.38	$ 2.58	$ 535.57	$ (2.56)
ZONE 4 CUSTOMER 1	15,100	$ 595.08	$ 2.24	$ 569.95	$ 2.68	$ 578.22	$ 4.46
ZONE 4 CUSTOMER 2	11,260	$ 435.54	$ 1.59	$ 442.59	$ 2.48	$ 444.25	$ 4.39
ZONE 5 CUSTOMER 1	14,560	$ 567.99	$ (0.17)	$ 587.59	$ (4.05)	$ 590.84	$ 1.51
ZONE 5 CUSTOMER 2	8,170	$ 313.71	$ (0.12)	$ 326.30	$ (2.16)	$ 317.48	$ 0.90
ZONE 6 CUSTOMER 1	15,100	$ 595.08	$ 0.27	$ 569.95	$ (1.25)	$ 578.22	$ 0.32
ZONE 6 CUSTOMER 2	11,260	$ 435.54	$ 0.14	$ 442.59	$ (0.87)	$ 444.25	$ 0.27
ZONE 7 CUSTOMER 1	22,450	$ 880.79	$ (0.37)	$ 892.42	$ (0.89)	$ 906.27	$ (1.20)
ZONE 7 CUSTOMER 2	11,340	$ 454.39	$ (0.08)	$ 451.46	$ (0.29)	$ 446.08	$ (0.49)
ZONE 8 CUSTOMER 1	16,960	$ 660.28	$ (2.67)	$ 633.79	$ (0.74)	$ 639.34	$ (2.11)
ZONE 8 CUSTOMER 2	7,590	$ 305.69	$ (1.09)	$ 294.34	$ (0.61)	$ 294.97	$ (1.08)

1. PJM and Alberta monthly spot price **adjusted** to have the same annual spot price as RTPII to allow annual bill comparison.
2. Multi-Zone Difference is net of single zone settlement. For example, customer 1 in Zone 1, zonal settlement bill is $609.86 - $4.33=$605.43.

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)***

Issue SG3-9: Which market participants should pay for losses and UFE?

- 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 SG3-10 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?

RECOMMENDATIONS:

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)***

Issue SG3-10: 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.

RECOMMENDATIONS:

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:

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

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

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.

1. 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.

2. 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.

3. 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.

4. 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)***

Issue SG3-11: 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:

See below.

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 MDMAs or by LDCs acting as MDMAs.

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.

MDC 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 SG3-8 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 SG3-7 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 SG3-22 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 SG3-17 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.

RECOMMENDATIONS:

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]
- 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

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[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.

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.
- 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.

[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.

ISSUE STATEMENT: ***(Final)***

Issue SG3-12: 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 SG3-11 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 mid-night of the last day), acquire the net system hourly loads by accessing database B referenced in issue SG3-11.

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*

[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.

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.

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 guidelines developed by the Board.

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)***

Issue SG3-13: 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, fibre 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.

RECOMMENDATIONS:

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.

VOTER SUMMARY:

Unanimous (18 Task Force members in favour)

DISSENTING OPINIONS:

None.

ISSUE STATEMENT:

(Note: This issue statement is an addendum to issue SG3-13, 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 SG3-13 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.

Issue SG3-14: 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

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

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.

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 specified.

ISSUE STATEMENT: ***(Final)***

Issue SG3-15: 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: ***(Final)***

Issue SG3-16: 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)***

Issue SG3-17: 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.

VOTER SUMMARY:

Unanimous (18 Task Force members in favour).

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG3-18: 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

$$\text{(a)}\quad CEC_{t,t+1} = \left(EMR_{t+1} - AMR_t\right) \bullet AP_{t,t+1}$$

$$\text{(b)}\quad CEC_{t+1,t+2} = \left(AMR_{t+2} - AMR_t\right) \bullet AP_{t,t+2} - CEC_{t,t+1}$$

Option 2

$$\text{(c)}\quad CEC_{t,t+1} = \left(EMR_{t+1} - AMR_t\right) \bullet AP_{t,t+1}$$

$$\text{(d)}\quad CEC_{t+1,t+2} = \left(AMR_{t+2} - EMR_{t+1}\right) \bullet AP_{t+1,t+2}$$

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.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG3-19: 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:

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

$$Load\ F_s = (DLF_p) \times (UFE) \times Load\ F$$

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(l 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.

RECOMMENDATIONS:

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 OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG3-20: 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).
- 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.

RECOMMENDATIONS:

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

2. 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 OPINIONS:

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.

Issue SG3-21: 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 date 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.

RECOMMENDATIONS:

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.

VOTER SUMMARY:

?

DISSENTING OPINIONS:

?

ISSUE STATEMENT: ***(Final)***

Issue SG3-22: 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 recommendation3-1, 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.

RECOMMENDATIONS:

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 SG3-12 through SG3-20 (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 that 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.

VOTER SUMMARY:

Unanimous (20 Task Force members in favour)

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG3-23: 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)***

Issue SG3-24: 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 four-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 $1,000. 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 filling 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.

RECOMMENDATIONS:

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

VOTER SUMMARY:

Unanimous (18 Task Force members in favour)

DISSENTING OPINIONS:

None.

ISSUE STATEMENT: ***(Final)***

Issue SG3-25: 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.

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	Distribution charges	Distribution losses applied to
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	Net* N/A	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	Gross	Net
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	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	Net N/A	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	Gross N/A	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 charge. Can generate power for consumption at their own site without interval metering.							
6. Embedded Wholesale Generator	Customer Charge: Generator payment:	IMO IMO	IMO IMO	IMO IMO	IMO IMO	IMO IMO	Yes—on power consumed N/A	Yes—on power consumed N/A

* 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 backup or other conditions.

*** 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 LDC's 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:

This issue was not discussed at Task Force level. A small working group developed this recommendation.

IMPLEMENTATION ISSUES:

?

VOTER SUMMARY:

Not voted on at Task Force level.

ISSUE STATEMENT: ***(Final)***

Issue SG3-26: 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 determined 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:

   (a) Peak demand.

   (b) Energy use.

   (c) 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.

APPENDIX D

Subgroup 4: Electronic Business Transactions

ISSUES LIST

1. Issue SG4-1: Standardised electronic business transaction system establishment D-2
2. Issue SG4-2: EBT system development and implementation D-4
3. Issue SG4-3: Market opening transactions set D-6
4. Issue SG4-4: Participation D-8
5. Issue SG4-5: Testing D-11
6. Issue SG4-6: Agent requirements D-13
7. Issue SG4-7: Arbitration D-15
8. Issue SG4-8: Reply window D-17
9. Issue SG4-9: Minimum access configuration D-19
10. Issue SG4-10: Governance of ongoing operations and maintenance D-20
11. Issue SG4-11: Funding for the initial work D-22

ISSUE STATEMENT:

Issue SG4-1: Which transactions between market participants should be implemented using a common electronic format and means in order to facilitate an efficient opening of the competitive retail market in Ontario?

OPTIONS:

1. Require all transactions to be conducted through hard copy (paper systems).

2. Require all transactions to be conducted through an electronic system

3. Allow market participants to develop unique, situation specific processes to manage information flows using either paper or electronic means.

4. Require that selected, high-volume transactions be conducted through a common electronic system with the balance being managed at the discretion of individual market participants.

BACKGROUND INFORMATION:

With the opening of the Ontario market, as many as 400 participants may emerge in the roles of LDC and retailer. A responsive and efficient market requires commonly used information and requests to be communicated between parties in a standard manner. This minimises the confusion of dealing with hundreds of potential partners and makes it possible to react to requests in a timely fashion.

In the last 40 years it has been proven over and over again that paper-based systems are not effective when dealing with a large number of partners and high-volume transactions.

There are insufficient time and resources available to find and classify the over 200 different message types that the Ontario market may require prior to market opening. In general with a team of professionals it takes at least a week to complete each message type (on average). That would delay the opening of the market for at least two years. Thus, a much smaller set of high-priority message types must be identified.

In Pennsylvania the market has allowed each LDC market participant to control their own version of a standard communications protocol. It has lead to the market having seven different standards for which each retailer must be certified. In each case the cost to certify is high enough that open market competition is quickly migrating to high-value pockets in a couple of areas in the state.

The Gas Industry Standards Board (GISB) was founded to remove communication and transaction barriers from the gas market in North America. While it took over a decade to implement the GISB standards, that effort taught a number of key lessons:

1. Standard planning up front makes changes easier in the long run

2. Attempting to tie markets together beyond political reach is a long and hard effort

3. The number of transactions that can be automated in one batch is under ten and more likely five.

SUMMARY OF GROUP DISCUSSION:

On three occasions the team met to discuss the issue of electronic business transactions (EBT). During those discussions the costs of not implementing EBT were discussed, as well as the costs of attempting to do too much. A number of illustrative scenarios were discussed. While complete costing was not available, the costs to automate and test transactions were discussed in detail. There was consensus on the issue of the need for standard transactions. There was also consensus on the need for some form of EBT. Indeed, it was the feeling of the Task Force that an EBT system was absolutely essential to the market and that the market should not open unless such a system is in place for certain high-volume transactions.

The team discussed the number and kinds of transactions to be automated. They felt that the initial number of transactions to be implemented should be limited to the very high-volume transactions or transactions where communication integrity is essential.

RECOMMENDATIONS:

Recommendation 4 was selected by the team to be recommended for implementation. Require certain, key high-volume transactions to be conducted through a common electronic system with the balance being managed at the discretion of the individual market participants (using a standardised format but not initially using EBT). The set of transactions for the common system may grow as the market continues to evolve and the volume of transactions grows.

IMPLEMENTATION ISSUES:

There are a large number of details that need to be addressed to create the working system. A number of these issues are discussed in subsequent recommendations.

VOTER SUMMARY:

Nineteen in favour; one opposed.

DISSENTING OPINIONS:

None specified.

ISSUE STATEMENT:

Issue SG4-2: Who should have responsibility for developing the specifications for and ensuring the timely implementation of a province-wide EBT system by market opening?

OPTIONS:

1. Rely on the OEB or other established government body to develop the standards and oversee the implementation.

2. Organise a group of stakeholder representatives to develop the specifications, review the detailed standards and oversee implementation.

BACKGROUND INFORMATION:

There is a need to guide the overall process of working through the options and issues that will arise in developing an EBT system.

Since many options exist, there is a need for frequent consultation with the guiding team. It is also important that that team be capable of rendering decisions with a minimum of consultation with others.

In other markets, the guiding team has had weekly meetings for up to three years. In most cases the market is not done evolving and the team continues to meet.

Since the EBT system has an impact on every segment of the retail market, the guiding team needs to take all of the stakeholders requirements into account.

In some markets, the guiding team was allowed to self form, in doing so, some segments of the participant community were over represented and the EBT system reflects that bias.

SUMMARY OF GROUP DISCUSSION:

The team discussed the issue in detail. On each occasion the team felt that a stakeholder team was able to represent the market participants in a timely fashion. The team also felt that in having a team, then the OEB could act as a facilitator and help mediate deadlocks on the guiding team, allowing the process to move more rapidly.

The discussion included a need to set business rules for the system and from that oversee the development of technical specifications. The need for a transitional team is required, due to the short timelines that are available to Ontario. In New Jersey, the team started with a “Complete” set of specifications and still had to hold the market opening back for a period of six months. The New Jersey team had 18 months to work on getting the market open. In Ontario, there is less than a year to get the same job done.

The group also considered when a permanent governance team might be formed and ready to take over the guidance of the system. It was felt that there are a number of natural points where this could happen and that the transition team, could and should proceed as far as possible, while the permanent team was being arranged. The best point was prior to the letting of the implementation contract, but there is no reason that the permanent team could not take over after than time.

Composition of the transition team was discussed. The need to balance the LDCs, retailers and other interests was stressed in the discussion by several people. The team size was also discussed; the general feeling was that a team of between seven and nine individuals was about right.

The transition team will have the need to create both the timing for the implementation of the EBT system and specifications, this means that the team will have to be involved and available for ten to 12 weeks and devote approximately 40 percent of their working effort to this task.

The transition team will also need the ability to make timelines and other decisions "stick." To that end the group discussed the need for the OEB to sponsor the team and to assist in the administration of the transition team.

RECOMMENDATIONS:

Appoint a group of stakeholder representatives to develop the specifications, review the detailed standards and oversee the implementation. This team will be assembled by the OEB and make appeals to the OEB, when and if needed. The governance team will take over the process once it has been appointed. Ideally the governance team will oversee the letting of the implementation contracts and the implementation process. Should the permanent governance team not be organised soon enough, a transmittal team will continue to be organised, so as to not impede the opening of the market.

IMPLEMENTATION ISSUES:

Funding for the operation of the guiding team and the development of the standards is an issue that needs to be resolved. Implementation funding is also an issue that must be addressed.

VOTER SUMMARY:

Unanimous (20 in favour).

DISSENTING OPINIONS:

None.

ISSUE STATEMENT:

Issue SG4-3: Which transactions should be conducted electronically at market opening?

OPTIONS:

1. Customer transfer to retailer and response.
2. Current meter-reading information.
3. Invoice and settlement transactions.
4. Historical customer and billing information requests.

BACKGROUND INFORMATION:

Prior to deregulation, most data handling is done within the billing and customer information systems. With the advent of deregulation, many of these internal transactions need to be shared among multiple parties. These transactions are key to settling the market and understanding who should be sent what information to settle the market.

In other competitive markets a core set of common transactions have been automated to increase efficiency and minimise the cost of entering into the competitive market. These transactions are normally handled electronically with a common template to ensure rapid delivery to the participants and the ability to track the delivery of the transactions.

SUMMARY OF GROUP DISCUSSION:

Group participants felt that the Settlement Code should address the core transactions listed in options 1 through 3 above. There was additional discussion around option 4. The feeling of several members of the group was that addressing option 4 was important because of the data intensity involved in the transaction. There were other members of the group that reserved judgement on option 4 because of uncertainty concerning retailer and customer interest in obtaining historical data, especially for small customers. There was a consensus on the items listed in options 1 to 3, that they should be included in the electronic transaction set and settlement code.

The group also discussed the ability to add additional transactions, once the EBT system was known and it became clear that the system would support those transactions without much in the way of additional costs. It was felt that because there are several transactions that are data intensive, and are sent with some frequency, that they are the next set of transactions to add to the system.

There was discussion on the inclusion of payment history in the customer and billing information, it is specifically excluded from that set of transactions for now, until the Settlement code is adopted and the final decisions on separate transmission of payment history is complete.

Since the code currently views this as a separate issue, the group felt that they should also take that tact.

As the Settlement Code is currently drafted, LDCs are required to provide historical customer information to either a retailer or the customer at no charge, provided that it is communicated electronically. Consequently, the subgroup felt that there was no option but to include that transaction in the initial set of transactions, however, since the code is not finalised, the group decided to wait to include it. The feeling was that the transition team could add transactions as required and that the current recommendations do not preclude appropriate additions. The representative from Measurement Canada indicates that having this information handled through an EBT system could be beneficial to resolution of customer disputes.

RECOMMENDATIONS:

At a minimum, the following transactions should be managed through an EBT system at time of market opening:

1. Customer-service transaction requests and associated communication between distributors and retailers.

2. Meter-reading information.

3. LDC invoicing to retailers and retailer settlement with LDCs.

4. Bill-reading data from retailers to LDCs for distributor consolidated billing.

Furthermore, a common data format will be developed for historical customer information, but use of the EBT system to transmit such information will be considered at a later date.

IMPLEMENTATION ISSUES:

Implementation issues for the transactions need to be handled as part of a specification and design project for the EBT system.

VOTER SUMMARY:

Unanimous (20 in favour).

DISSENTING OPINIONS:

None.

ISSUE STATEMENT:

Issue SG4-4: Who will be required to participate in the EBT system?

OPTIONS:

1. No one is required to conform to the EBT standards—participation is voluntary.
2. Participation is mandatory for large utilities, and is voluntary for utilities serving fewer than X residential customers. (Where "X" is an arbitrary number).
3. Participation is mandatory, all market participants are required to adhere to the EBT standards and have direct access to the message transmission system on site.
4. Participation is mandatory; all market participants are required to adhere to the EBT standards. However, side arrangements may be made with third parties for transmission services.

BACKGROUND INFORMATION:

There are two elements to this issue; the first is whether or not to require market participants to conform to a set of standards for formatting transactions, or allowing those participants to use any format that they desire to use. The second element is whether to mandate the use of a single information transmission system for participants in the market.

Common formats allow everyone to support a single method of importing and exporting data from participants systems. It also allows new participants to minimise the cost of joining the market. Overall it levels the playing field for everyone, by requiring a common format.

Participation in a common system goes beyond the use of formats for the transactions to specifying the requirement to support a single method of transmission for the transactions. This common method would at a minimum require everyone who uses an electronic formatted message to send the message using common electronic means. This would negate the ability of a participant to send electronic formats via fax or to phone them in to the receiver.

SUMMARY OF GROUP DISCUSSION:

The subgroup agreed with the need for common formats. The feeling was that without a common format, the cost to do business would be too high for the market to be competitive. There was extensive discussion regarding the required level of participation. There was agreement that the benefits of requiring all market participants, regardless of size, to use the same EBT process would have a unifying effect on the market. However, there were differences of opinion concerning whether or not to allow small LDCs to use an alternative means of transmitting messages.

The group discussed various limits for the minimum participation size. With over 100 LDCs with fewer than 1,000 customers, the size issue left too many market participants unable to participate in the system. It also required that too many retailers and others be ready to deal with a barrage of paper, adding to the overall cost to operate the market.

One issue considered was the period within which all participants would be required to conform with new transaction sets as they are implemented. This issue is attempting to reconcile the need for participants to modify their systems to interface with the EBT system requirements. The group discussed several options before settling on a 90 phase-in period for each participant, beginning from the "live date" of the new transaction(s) on the system.

The group talked openly several times on the need to ensure that all options that are available to serve the market in Ontario be available to the transition team. Some of the possible options are only valid if everyone uses the same service as well as the same set of transactions. Initial discussions indicate that one or more of these options may offer some of the lowest transaction costs. Since one of the overall goals is to minimise the cost of opening and operating the market, the team felt that it was important to make it possible for the transition team and the OEB to mandate participation in a single system. This would only happen if the best possible option for Ontario is one of the options that includes the need to have everyone on the same system.

The use of a single system would potentially offer lower transmission fees and other cost improvements. It also removes competition from the market to provide this service and so the development of any option would have to be weighed to ensure that Ontario did not trap themselves in a situation that would add costs to the market. Since the analysis of the options and the final decisions are being left to the transition team, it was felt that there was a need to provide the option to mandate use of a single system, without requiring it. To this end recommendation 4 was developed.

A second issue concerned the requirements for entry into the system. The discussion centred on low barriers to entry into the system with minimal costs, as addressed in issue SG4-9.

RECOMMENDATIONS:

1. Mandate the use of common formats for all market participants for a defined set of transactions.

2. The initial set of transactions are mandatory on the day the market opens. A reasonable phase-in will be established by the EBT governance committee for any new transactions that are added after market opening.

3. Require market participants to use a common method for transmission of the defined set of transactions, allowing entities to contract with a third-party service supplier for the EBT transmission service.

4. Mandate that should an EBT architecture be chosen that requires market participants to utilise a single system (e.g., a single, intelligent hub), all participants must use that system.

IMPLEMENTATION ISSUES:

Minimum standards need to be set requiring regular system access (checking for new messages), receipt acknowledgement and action response time for those participants who chose to contract with a EBT transmission service provider.

VOTER SUMMARY:

Nineteen in favour, one against.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT:

Issue SG4-5: How should testing be carried out to support the EBT system and the use of its formats?

OPTIONS:

1. Each retailer is required to test separately with each LDC

2. A central testing organisation exists and once testing is complete with the central organisation, the participant is certified to operate with any other certified market participant.

BACKGROUND INFORMATION:

As competitive markets have opened in most US states, the testing requirements (system and format compatibility) have been addressed on a LDC by LDC basis. This has minimised the costs for each LDC to be ready to enter the market and allowed wide latitude to LDCs to customise the format standards to support their own internal requirements. However, this practice has fragmented each state market into LDC markets, with separate rules for each LDC territory.

While cost effective for LDCs, this practice has become a significant barrier to entry for many retailers. The current estimated costs for a retailer to become certified in these types of markets can range from $15,000 to $35,000 dollars for each LDC.

After years of growing costs and an inability to communicate, the gas industry formed the Gas Industry Standards Board (GISB). GISB mandated central testing as a way to maintain a uniform standard and open the market to a wider array of participants.

SUMMARY OF GROUP DISCUSSION:

There was agreement in the group that central testing and certification were required to ensure a level playing field in Ontario's competitive market. The group also felt that the details of testing procedures should be left to the EBT governance body.

No member of the subgroup was interested in opening discussion on LDC testing of EBT. The group in general felt that the cost to set-up and manage LDC testing at the LDC was too expensive to be a viable option in a market with so many LDCs.

RECOMMENDATIONS:

The EBT governance team should have the ability to set testing requirements for each of the transactions it governs. The test set should be part of the approved format.

IMPLEMENTATION ISSUES:

No mechanism is currently available for managing testing. Implementation of a central testing authority and the funding for that authority will have to be worked out, once a governance mechanism is approved.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT:

Issue SG4-6: What conduct and accountability standards should be placed on third-party EBT transmission service providers and those who contract with them?

OPTIONS:

1. Hold participants (LDC or retailer) responsible for the actions of their agents.

2. Hold agents to the same standards and rules as all other market participants.

BACKGROUND INFORMATION:

Upon market opening it is quite likely that third-party agents will enter the market to provide EBT transmission services to both retailers and LDCs.

Because of the speed of the EBT system, knowing who knew what, when is critical to the functioning of the market. As the market evolves it will be less and less able to differentiate the knowledge of the agent from the knowledge of the client that they are acting for.

Without the ability to quickly sort out who initiated transactions (the agent or the client) and who was being represented (i.e., differing parties that would not normally be allowed to exchange data and information), the agent may have the ability to influence the development of the competitive market in Ontario.

SUMMARY OF GROUP DISCUSSION:

The group discussed this topic and felt that holding the agent to the same set of standards as the participant would maintain a fair market. This would minimise the possibility that any agent could circumvent the rules of the market and unduly influence its future direction.

The group discussed the definition of an EBT agent, and felt that it was anyone who provided EBT services of any sort to a participant in the Ontario market, whether that agent was a participant or not.

RECOMMENDATIONS:

The Task Force felt that the agency role for EBT services was no different than for other obligations; and, therefore, it was unnecessary to have a special rule in the Code governing the relationship for EBT.

IMPLEMENTATION ISSUES:

None

VOTER SUMMARY:

Not relevant.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT:

Issue SG4-7: How will disputes that arise surrounding transactions conducted using the EBT system be resolved?

OPTIONS:

1. Chose no mechanism and allow participants to settle disputes directly, including but not limited to relief in the courts.

2. Require the OEB to intervene in any dispute as the first line of resolution.

3. Create an arbitration process to support resolution of issues.

BACKGROUND INFORMATION:

The majority of issues arising from EBT involve the date and time of receipt (or non-receipt) and whether or not a transaction is complete. Most of these issues can be quickly resolved if a record of the transactions exists. To maintain the speed of the market, it is important that these issues be resolved very quickly. In other competitive markets the standard is that from the time an issue is raised until it must be resolved is typically five business days. Maintenance of a process for rapid resolution of issues maintains market integrity and minimises disruption that can arise around dispute issues. Since a pattern of abuse may arise, it is important to track the issues and assist the market in removing the patterns.

SUMMARY OF GROUP DISCUSSION:

The options considered are described in the paragraphs below:

1. Direct resolution of issues between parties would require the parties to either settle the issue or resort to the relief allowed under the law. The first line of resolution would be some form of two party discussions (as required by the Transitional Distribution Licence). Should that fail, resolution would move to the court system. Most EBT-based issues are small in size and require a rapid resolution to maintain the speed of the market. Inherently the court system is not a rapid way to resolve small disputes.

2. Allowing the OEB to intervene would require the Board to maintain the staff and knowledge to intervene in disputes. This would allow the existing license mechanism to continue to address larger issues, while moving the small issues around EBT transactions to the OEB for resolution.

3. Creating a separate method for resolving typical EBT issues while allowing the results to be reviewed on a periodic basis by the OEB or another organisation to allow relief for incidents that form patterns. While each of these methods can support the market, options 2 and 3 allow the market to develop at its own speed. Option 3 allows for a low cost method to be

introduced to the market to resolve specific issues that occur frequently in an emerging market.

Whether the method will be required in five years in the Ontario market is an open issue. As the market evolves, the number of disputes should decrease with maturity.

The subgroup discussed the arbitration issue at length. The overall feeling of the group was that some form of arbitration was required to shorten the turnaround time and hold the costs down.

The group did not discuss the requirement to limit the term of the arbitration method (when it should expire) or the details of the mechanism.

RECOMMENDATIONS:

1. The EBT system must be designed to include the automated retention of readily accessible, auditable records of transactions. (This would go a long way toward pre-empting a large number of common disputes in other jurisdictions.) The system will retain records as required by other codes or as required by Revenue Canada.

2. Disputes that are not resolved under recommendation 1 (above) would be bound by the dispute mechanism described in the applicable code.

IMPLEMENTATION ISSUES:

Pending the outcome of the other issues, the ability to implement this recommendation is unknown. Only when the issues are finalised can the rest of the implementation issues be known.

VOTER SUMMARY:

Unanimous.

DISSENTING OPTIONS:

None.

ISSUE STATEMENT:

Issue SG4-8: What is the maximum allowable time frame for acknowledging receipt of and completing action on an EBT transaction?

OPTIONS:

1. Set one standard for all required EBT transactions.

2. Require the EBT development group to set parameters, not to exceed those defined by the detailed business processes specified in the Code.

BACKGROUND INFORMATION:

The decisions that have already been made by the RSC Task Force provide guidance for many of the transactions that the EBT system is expected to process. The guidance is specific enough to drive the overall market, but not the internal requirements of the EBT system and the specific responses that are required for failed messages and incomplete transactions.

These internal timings depend on the EBT options selected and setting them in the settlement code would limit the EBT options available for Ontario.

SUMMARY OF GROUP DISCUSSION:

Initially the group was concerned about the ability of the governing team to set new timing for the market. When the discussion progressed, the group realised that there were a number of internal timings that had to be set inside of the existing windows for the EBT system to work. The discussion then turned to which transactions the governing team would be allowed to set timings for. The group settled on the team being allowed to set timings for those transactions that were assigned to the EBT system, so long as the overall window of time for response did not change.

RECOMMENDATIONS:

Require the EBT governing team or the transition team to set internal timings for the EBT transactions, such that they do not violate the windows for transactions as defined in the Settlement Code.

IMPLEMENTATION ISSUES:

Determined reply windows as part of EBT process.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT:

Issue SG4-9: When should access criteria for participation in the EBT system be defined?

OPTIONS:

1. Following the specification and design work of the EBT development team.

2. Define minimum access criteria within the Code so that participants will understand the required investment to participate in the system.

BACKGROUND INFORMATION:

The final design of the EBT system and the corresponding information technology requirements to participate could present a barrier to entry in the market. Should the requirements be set too high, many companies will be unable to participate at all. If the minimum requirements are not stated, uncertainty will cause some level of anxiety in the participant community.

Since all of the design options can be expended to support a low cost option, the design options are not limited by taking the approach of mandating a minimum configuration for access.

SUMMARY OF GROUP DISCUSSION:

Because of the low impact on the functionality of the system and the importance of certainty for participants the subgroup felt that it was important to address this issue. The group also felt that it was important to be specific in the requirements.

RECOMMENDATIONS:

Require that the design of the EBT system allow for access using a standard PC and Web browser as a minimum requirement. The specific requirements will be set by the governing body.

IMPLEMENTATION ISSUES:

None.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT:

Issue SG4-10: How should the EBT system be governed so that it can support changes to the market and its needs?

OPTIONS:

1. Allow the OEB to maintain control.

2. Contract to a service provider to control changes.

3. Develop a governance board of stakeholders.

4. Do not govern the system.

BACKGROUND INFORMATION:

Since the market will evolve and change in Ontario, it is important to be able to update and change the EBT system as the market changes. While the initial set of three to four transactions is enough to support the opening of the market, when 20 percent of the customers in Ontario are using alternative suppliers, the number of manual transactions will swamp many retailers and LDCs. To avoid this problem, a governing mechanism needs to be put in place to support the evolution of the EBT system.

SUMMARY OF GROUP DISCUSSION:

Subgroup participants generally favoured the formation of a stakeholder group with the ability to make the following kinds of decisions:

1. Development of new and updated functional requirements for the system.

2. Approval of technical requirements and transaction formats.

3. Detailed rule development for use of the EBT system.

4. Detailed rule development for testing of the EBT system.

5. Schedules for improvements to be available to the users of the system.

RECOMMENDATIONS:

The OEB will form and oversee a stakeholder governance group with fair representation from all parties. The stakeholder group will be responsible for the following functions:

1. Development and maintenance of the functional requirement for the EBT system.

2. Oversight of the addition of new transactions.

3. Approval of technical requirements for the EBT system.

4. Approval and oversight for implementation and maintenance of the EBT system.

5. Rule development of the EBT system.

6. Testing requirement oversight for the EBT system.

7. Oversight of the operations of the EBT system.

IMPLEMENTATION ISSUES:

The OEB will have to establish the governance team and the rules for staffing it. There is still an open issue whether any further detail about the governance committee should be included in the Code. Funding of the group is an open issue that needs to be addressed.

VOTER SUMMARY:

Nineteen in favour; one abstention.

DISSENTING OPINIONS:

None.

ISSUE STATEMENT:

Issue SG4-11: How should the EBT system's specification and design phase costs be funded?

OPTIONS:

1. Impose a fee on each customer switching.
2. Impose a fee on the license of each LDC and retailer.
3. Recover over a three-year period from customers switching.
4. Recover of a three-year period from all customers in the Ontario market.

BACKGROUND INFORMATION:

To support opening the market, there is a need to start this work immediately. In most open markets the EBT work has taken over 18 months. Because there are a number of markets that have opened and there is a body of knowledge on how not to do it. The group felt that they could with the time available complete the development of an EBT system to support opening the Ontario market in the summer/fall of 2000.

To do this, there are five steps the group has outlined:

1. Development of the settlement code input—mostly complete.
2. Development of the business specifications for the system (four to six weeks of work, with a general review period of two to four weeks to follow).
3. Development of the technical specifications for the system (five to seven weeks of work with a general review period of two to four weeks to follow).
4. Development of the EBT system (20 to 30 weeks of work).
5. Testing and rollout of the system (four to six weeks).

If the team were to stick to the fastest track, the overall time line would be 37 weeks, without time for RFPs or modification. Should the system take the slower path it would be in the range of 57 or more weeks, completely missing the window for next year.

SUMMARY OF GROUP DISCUSSION:

The group felt that it was critical to get this effort off the ground and develop at least the business and technical specifications. Consequently, the group considered a number of funding options. To put the options in context the group discussed what would happen to the market if there was no EBT system. The group felt that the overall costs to operate the market would rise with the need for a large number of paper-based transactions. They also felt that the market would open more slowly. Because of both of these issues, they felt that there would be costs that would be spread to all the LDC customers, because of the additional costs to operate the LDC. Since those costs would be very hard to separate, the overall feeling was that all customers would bare at least some of the additional costs.

The group discussed the need for the final system to be self-funding. The overall feeling is that if the options are carefully reviewed that it will be possible to create a self-funding system for a very small transaction fee. Putting the operating and maintenance costs directly on the shoulders of those customers who are taking advantage of the open market.

The group discussed the idea that the system, like the IMO, as a cost of opening the market. Given that operating the market will be more expensive without the system, it was felt that the implementation costs should be considered a transition cost.

RECOMMENDATIONS:

Have the OEB fund the development of business and technical specifications of the system, while the Settlement Code is being finalised. Develop a business case to support the implementation of the system once the business specifications are reviewed, in parallel with the development of the technical specifications and cost estimates.

IMPLEMENTATION ISSUES:

The OEB will need to find the funding to support this fast track effort.

VOTER SUMMARY:

Unanimous.

DISSENTING OPINIONS:

None.

APPENDIX E

Definitions

(Note: Many of the definitions below were taken from the work of the DSC Task Force which, in turn, took many definitions from the following areas. The initials following each definition correspond to the sources listed below.)

A	*Bill 35*, Electricity Act, 1998, *Schedule A, Section 2, Definitions;*
MR	*Market Rules for the Ontario Electricity Market, Chapter 11, Definitions;*
TDL	*Transitional Distribution License, Part I, Definitions;*
TTL	*Transitional Transmission License, Part I, Definitions;*
DSC	*Distribution System Code Task Force*

"Accounting Procedures Handbook" means the handbook approved by the Board and in effect at the relevant time, which specifies the accounting records, accounting principles and accounting separation standards to be followed by the distributor. *(TDL)*

"*Act*" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule B. *(TDL)*

"Affiliate," with respect to a corporation, has the same meaning as in the *Business Corporations Act*. *(A, MR, TDL)*

"Affiliate Relationships Code" means the code, approved by the Board and in effect at the relevant time, which among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies. *(TDL)*

"Ancillary services" means services necessary to maintain the reliability of the IMO-controlled grid; including frequency control, voltage control, reactive power and operating reserve services. *(MR, TDL)*

"Board" means the Ontario Energy Board. *(A, TDL)*

"Building" means the building, portion of a building, structure or facility. *(DSC)*

"Competitive electricity service costs" are those charges billed through the IMO or paid to embedded retail generators or neighbouring distributors through load transfer arrangements that cover services that are deemed by the Board to be competitive. Such charges will apply to electricity supply whether such supply is provided via standard supply service or a competitive retailer.

"Competitive retailer" is a person who retails electricity to consumers who do not take standard supply service.

"Consumer" means a person who uses, for the person's own consumption, electricity that the person did not generate. *(A, MR, TDL)*

"Cycle billing" means the practice of billing a block of consumers whose meters are read according to a common meter-reading cycle as if all meters were read on the same day, even though meter-reading practices result in some meters being read within a couple of days, plus or minus, of the target read date. For example, a certain percentage of a block of consumers whose meters were scheduled to be read on the first day of two consecutive months might in fact be read on the second day of the first month and the third day of the second month. A different percentage of consumers might have had their meters read on the actual target dates.

"Director" means the Director of Licensing appointed under Section 5 of the *Act*. *(TDL)*

"Distribute," with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less. *(A, MR, TDL)*

"Distribution losses" are energy losses resulting from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows.

"Distribution loss factor" means a factor(s) by which metered loads must be multiplied such that when summed equal the total measured load at the supply point(s) to the distribution system.

"Distribution services," means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sale of electricity to consumers under section 29 of the *Act*, for which a charge or rate has been established in the Rate Order. *(TDL)*

"Distribution system" means a system for distributing electricity at voltages less than 50 kV, and includes any structures, equipment or other things used for that purpose. *(A, MR, TDL)*

"Distribution System Code" means the code, approved by the Board, and in effect at the relevant time, which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to consumers and retailers and provides minimum technical operating standards of distribution systems. *(TDL)*

"Distributor" means a person who owns or operates a distribution system. *(A, MR, TDL)*

"*Electricity Act*" means the *Electricity Act, 1998*, S.O. 1998, c.15, Schedule A. *(MR, TDL)*

"Electronic Business Transaction (EBT) System" is a computer-based transaction mechanism for transmitting common format data between market participants.

"Embedded retail generator" is a generator who is not a wholesale market participant and whose generation facility is connected at the distribution level.

"Embedded wholesale consumer" is a consumer who is a wholesale market participant whose facility is not directly connected to the IMO control grid but is instead connected at the distribution level.

"Embedded wholesale generator" is a generator who is a wholesale market participant, whose generation facility is not directly connected to the IMO control grid but is instead connected at the distribution level.

"Generate," with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system. *(A, TDL)*

"Generation facility" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose. *(A, MR, TDL)*

"Generator" means a person who owns or operates a generation facility. *(A, MR, TDL)*

"Holiday" means a Saturday, Sunday, Statutory holiday or any day that the Board's offices are closed. *(TDL)*

"IMO" means the Independent Electricity Market Operator established under the *Electricity Act*. *(A, TDL)*

"IMO Controlled Grid"[1] means the transmission systems with respect to which, pursuant to agreements, the IMO has authority to direct operation. *(A, TDL)*

"Interval meter" means a meter that measures and records electricity use on an hourly or sub-hourly basis.

"Load transfer" means a network supply point of one distributor that is supplied through the distribution network of another distributor and where this supply is not considered a wholesale supply point.

"Lock box arrangement" means an arrangement where a creditworthy institution (typically a bank or some other stable financial institution) is designated by two parties to accept payment from consumers on behalf of the parties and to distribute the collected revenue to the parties according to prescribed rules. For example, under retailer-consolidated billing, a remittance processing institution would accept payment from all parties and pay the distributor for all relevant costs before paying any residual amount (e.g., the retailer's margin) to the retailer.

"Market Rules" means the rules made under section 32 of the *Electricity Act*. *(MR, TDL)*

"Meter installation" means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment.

"Minister" means the Ministry of Energy, Science and Technology. *(A, MR, TDL)*

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[1] Market rules have "operating agreements" for "agreements" and "operations" for "operation."

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

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

"Non-competitive electricity costs" include charges from the IMO for services deemed by the Board to be non-competitive services plus charges for distribution services

"Non-interval meter" means a device that measures and records electrical usage cumulatively over the meter reading period.

"Performance standards" means the performance targets for the distribution and connection activities of the distributor as established by the Board pursuant to section 82 of the *Act*. *(TDL)*

"Power factor" means a variable equal to the ratio of kW and kVa demand

"Prepaid meters" means meters allow a consumer to purchase a credit for a certain amount of electricity at a fixed price from a distributor or retailer by having the amount posted to the meter at the consumer's location. When the purchased amount of electricity has been used, the meter will automatically interrupt electricity supply to the location.

"Rate" means any rate, charge or other consideration, and includes a penalty for late payment. *(TDL)*

"Rate Handbook" refers to the document which outlines the regulatory mechanisms which the OEB will apply to the development and adjustment of electric distribution rates over the first term of Performance Based Regulation (PBR) in the Province of Ontario.

"Registered facility" means a facility registered with the IMO that is capable of supplying physical services and/or capacity reserve.

"Regulations" means the regulations made under the *Electricity Act*, or the *Act*. *(TDL)*

"Retail," with respect to electricity means,

(a) to sell or offer to sell electricity to a consumer,
(b) to act as agent or broker for a consumer with respect to the sale or offering for sale of electricity or
(c) to act or offer to act as an agent or broker for a consumer with respect to the sale or offering for sale of electricity. *(A, MR, TDL)*

"Retail Metering Code" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes metering and meter reading standards and rules for providing interval metering. *(TDL)*

"Retail Settlements Code" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers. *(TDL)*

"Retail settlement variance account" or "RSVA" is an account kept by each distributor for the purpose of recording quantifiable variances between billed revenue and costs for competitive and non-competitive wholesale services resulting from the valid application of the rules and procedures identified in this Code.

"Retailer" means a person who retails electricity. *(A, MR, TDL)*

"RSC" means this Retail Settlement Code.

"Service area," with respect to a distributor, means the area in which the distributor is authorised by its licence to distribute electricity. *(A, TDL)*

"Service transaction request" or "STR" means a mechanism that initiates a change from current service provision to alternative service provision.

"Standard Supply Service Code" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the "*Electricity Act*." *(TDL)*

"Time-of-use meter" means a device that measures and records electrical usage during pre-specified periods of the day cumulatively over a meter reading period.

"Total losses" means the sum of distribution losses and unaccounted for energy.

"Transmission system" means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose. *(A, MR, TDL)*

"Transmission System Code" means the code, approved by the Board, that is in force at the relevant time, which regulates the financial and information obligations of the Distributor with respect to its relationship with consumers, as well as establishing the standards for connection of consumers to, and expansion of a transmission system. *(TTL)*

"Transmit," with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts. *(A, TDL)*

"Transmitter" means a person who owns or operates a transmission system. *(A, MR, TDL)*

"Unaccounted for energy" means all energy losses that can not be attributed to distribution losses. These include measurement error, errors in estimates of distribution losses and unmetered loads, energy theft and non-attributable billing errors.

"Unmetered loads" means electricity consumption that is not metered and is billed based on estimated usage.

“Wholesale consumer” means a person that purchases electricity or ancillary services in the IMO-administered markets or directly from a generator. *(TDL)*

“Wholesale market participant” means a person that sells or purchases electricity or ancillary services through the IMO-administered markets.

“Wholesale settlement cost” means costs for both competitive and non-competitive services as defined by the Board and as calculated according to rules and procedures contained in sections 3 and 4 of the Code.

“Wholesale supplier” means a person who sells electricity or ancillary services through the IMO-administered markets or directly to another person, other than a consumer. *(TDL)*