REPORT OF THE
ONTARIO ENERGY BOARD
PERFORMANCE-BASED REGULATION
DISTRIBUTION RATES TASK FORCE

MAY 18, 1999

Prologue

The Ontario Energy Board (OEB) is proposing performance-based regulation (PBR) for the electricity distributors in Ontario. The OEB's approach in developing a PBR framework for electricity distribution is to involve the stakeholders through task force efforts. As such, the OEB set up four PBR task forces consisting of volunteer stakeholders to examine the following: cap mechanisms, yardstick grouping, implementation issues, and distribution rates. The task forces had a total of 83 members representing various electricity distributors, gas utilities, customer groups, and special interest groups, as well as Ministry of Energy, Science and Technology and OEB Staff

The Task forces were formed in mid-January and worked on the assigned tasks for approximately 3 months. The task force meetings were co-managed by OEB consultants, Michael King and Frank Cronin of PHB Hagler Bailly, who also provided the task forces with technical expertise on PBR and restructuring issues in general.

To address the diversity of scope and the large number of emerging issues, working groups were formed within the task forces. Each working group produced reports which Board staff has collated into the task force reports.

All four task forces ran into concerns that led to the common proposal that the OEB should allow for a regulatory transition period. The regulatory transition period would allow utilities the opportunity to meet restructuring requirements without rigorous regulatory impositions, and allows for the collection of consistent and robust baseline data for PBR. The task forces agreed that a three-year first generation PBR plan should apply for the transition period to avoid gaming opportunities, in anticipation of PBR, during the transition period.

The first generation plan will have sophisticated incentive parameters (i.e. industry specific price indexes and productivity factors) developed from data collected from the electricity distributors and will also have risk mitigation terms (i.e. earnings-sharing). However, inconsistencies in data and utility practices precluded the implementation of yardstick groupings and a complete set of comprehensive performance standards applied to all distributors for the first generation plan.

The OEB would like to express its sincere appreciation for the conscientiousness of the task forces members and the time they expended on the task force efforts, as well as its admiration for the collaborative attitude demonstrated by each of the task forces. Board staff and their consultants are confident that the outcomes of the discussions by the task forces will facilitate the production of a draft Board PBR Rate Handbook and result in a fair and practical PBR framework for the electricity distributors in Ontario.

Outline

PARTICIPANTS

Name	Title	Association
Ralph Amar	Rates Manager	Mississauga Hydro
Bruce Bacon	Senior Consultant	Econalysis Consulting Services
Tanya Bodell	Principle	Putnam, Hayes & Bartlett
Bill Cannon	Associate Professor	Queen’s School of Business, Queen’s University
Al Clark	General Manager & Secretary	Waterloo North Hydro
Doug Cummings	Secretary-Treasurer	Hamilton Hydro
Gerry Dupont	Assistant General Manager/Controller	Nepean HEC
Gordon Firman	Manager, Electricity Operations	Ministry of Energy, Science and Technology
Ed Jambor	Sr. Manager of Operations	London Hydro
Una O’Reilly	Senior Policy Advisor, Issues Management	Ministry of Energy, Science and Technology
Ray Payne	General Manager	Municipality of Chatham-Kent
Wayne Panko	Director, Corporate Support	Pickering Hydro
Mike O’Shea	Deputy ERO	OEB
Adrian Pye	Senior Research Analyst	Enbridge Consumers Gas
Ramona Abi Rashed	Director of Finance	Whitby Hydro
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Pran Sengupta	Director of Finance	Sarnia Hydro
Ken Snelson	Consultant	AMPCO
Rick Stevens	Senior Advisor, Business Strategy	Ontario Hydro Services Co.
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Maurice Tucci	Officer	Municipal Electric Association
Rick Zebrowski	Manager, Rates & Regulated Services	Toronto Hydro

TASK FORCE MANAGEMENT TEAM

Co-Manager	Michael King	Vice-President, PHB Hagler Bailly Consulting, Inc.
Co-Manager	Frank Cronin	Senior Advisor, PHB, Hagler Bailly Consulting, Inc.
Coordinator	Judy Kwik	OEB, Research & Policy Analyst
Co-coordinator	Edward Sweet	OEB, Regulatory Officer

OEB DISTRIBUTION RATES TASK FORCE REPORT

1. INTRODUCTION

The objective of the Distribution Rates Task Force is to develop rate guidelines for distribution services and assess the financial and customer implications of rate restructuring.

The task force developed and evaluated options for setting initial unbundled PBR rates. In doing so, the task force discussed the following issues:

- Identification of distribution services;
- Determination of initial rates;
- Unbundling of distribution and commodity rates;
- Rate flexibility;
- Determination of rate base and return on equity;
- Impact of market-based rate of return and taxes on revenue requirement; and
- Treatment of contributed capital.

Two work groups were formed within the task force as follows:

Work Group 1 – Distribution Services

Chair:	Rob Reid	Great Lakes Power Ltd.
	Ramona Abi Rashed	Whitby Hydro
	Ralph Amar	Mississauga Hydro
	Bruce Bacon	Econalysis Consulting Services
	Gerry Dupont	Nepean HEC
	Gordon Firman	Ministry of Energy, Science and Technology
	Mike O’Shea	Ontario Energy Board
	Wayne Panko	Pickering Hydro
	Ray Payne	Municipality of Chatham-Kent
	Maurice Tucci	Municipal Electric Association

Work Group 2 - Rate Structure

Chair:	Ed Jambor	London Hydro
	Al Clark	Waterloo North Hydro
	Doug Cummings	Hamilton Hydro
	Una O'Reilly	Ministry of Energy, Science and Technology
	Adrian Pye	Enbridge Consumers Gas
	Pran Sengupta	Sarnia Hydro
	Ken Snelson	Association of Major Power Consumers of Ontario
	Rick Stevens	Ontario Hydro Services Co.
	Don Thorne	Milton Hydro
	Rick Zebrowski	Toronto Hydro

The intent is for Board Staff to draw on the task force's discussions and recommendations in preparing an Ontario Energy Board (OEB) draft rate handbook for the electricity distributors. The OEB will hold a public consultation on the draft rate handbook in the summer of 1999, with issue of the rate handbook expected in the fall of 1999. The distributors will then be in a position to file evidence according to the guidelines contained in the rate handbook for a rate order establishing unbundled PBR rates prior to the introduction of open access expected in the fall of 2000.

2. DISTRIBUTION SERVICES

The scope of the Services Work Group was to identify various services that would be detailed on a customer's bill or those services that would have a separate rate mechanism (e.g. work on customer owned facilities).

It was also decided that a review of the Draft Standard Supply Service Code, Affiliate Relationship Code and the Market Development Committee's (MDC) Final Report should be undertaken to ensure a thorough understanding of the pertinent issues.

The following topics were discussed:

(1) Core Services
(2) Fringe Services
(3) Contestable Services

2.1 Core services

The following list of core services was determined. This was primarily based on Section 2.7.1 of the Draft Standard Supply Service Code published by the OEB.

- Standard supply service administration fee
  - All costs associated with the administration of the settlement process but not administrative charges associated with the distribution wires business.
- Electrical energy (the weighted average price times consumption)
  - This element would consist of the spot price pass through energy charge.
- Ancillary services (if not included in the spot market price)
  - These charges may be included in the Independent Market Operator's (IMO) charges.

- Distribution charges
  - All of the costs associated with the operation of the LDC that are not broken out as specific charges in other sections.
- Transmission (including losses and unaccounted for energy)
  - These charges result from the IMO for transmission service
- Special charges (e.g. new account charges, service notices)
  - All of the costs associated with specific charges for services that benefit a small portion of the rate base. There are several examples in place today including lawyer's charges, late payment charges, disconnect / reconnect charges.
- Market power credits or rebates
  - These charges may be included in the IMO charges.
- Uplift charges
  - These charges may be included in the IMO charges. There has been discussion that Rural Rate Assistance would be included in this category.

Recommendation

The following list of services should be accepted as the "core services" of an LDC for purposes of PBR. Any items not listed should be covered under fringe or contestable services as defined in the following text.

2.2 Fringe Services

Fringe services were defined as competitive services that the LDC could supply. The following fringe services were discussed.

- Water Heaters
- Streetlights

- Sentinel Lights
- Construction of Customer-Owned Facilities
- Maintenance of Customer-Owned Facilities
- ESCO Services (e.g. energy management, power quality services, etc.)
- Shared services provided to affiliates (e.g. Billing taxes for the City)
- Shared services provided to others (e.g. billing for a neighboring Utility)

There was consensus that these services should not be subsidized and that full cost pricing practices should be utilized.

The main issue that must be decided deals with the treatment of affiliates and the impact of their creation on small utilities.

Recommendation

Any service that is competitively offered in the marketplace can be offered by LDC's as long as it is fully costed and not subsidized by the rate base. The long term viability of the service will be determined by the marketplace.

2.3 Potentially Contestable Services

The definition of "contestable services" are those services that a customer can choose to receive from the LDC or from an alternate supplier. The following lists the services that have been identified as potentially contestable to date:

- Meter Service Provider
- Meter Data Management Agent

- Billing (Calculation, production, mailing)

The definitions of these services are those listed in the MDC Final Report.

There was consensus that these services must not be subsidized and their full cost must be available to customers so they can make a decision regarding their supplier in the future. The task force's thinking is that these services do not need to be separated on the bill until the services are deemed contestable.

The issue of how to calculate credits given to customers as a result of changing supplier of contestable services was discussed at length. The only way to hold the LDC harmless would be to calculate the credit using marginal pricing. It is therefore a definite possibility that a credit equal to zero could be given if the number of customers choosing an alternate supplier was not large enough to cause a real cost reduction for the LDC. This practice would likely limit the creation of a competitive market for these services. A discussion on this issue is in the MDC's final report. Further discussion by the Task Force on this issue is presented in Section 3.5.

3. INITIAL RATES AND RATE STRUCTURE

3.1 Assumptions and Requirements for Separate Cost Tracking

It was assumed that the following costs will need to be tracked separately:

- Transmission charges and IMO fees;
- Costs associated with the core distribution wires business;
- Distribution system losses;
- Costs associated with metering (purchase, installation, testing and maintenance of meters);
- Meter reading;
- Costs associated with the billing cycle (assume that this includes the processing and mailing out of bills, account inquiry, and collections); and
- Fringe services (non-core services that the LDC may continue to provide such as water heating, water billing for the municipality, services for other LDC's, etc.).

The Task Force notes that although these costs should be tracked separately, separate rates do not necessarily have to be developed and shown unbundled on a customer's bill. Once a rate structure is agreed upon, further discussion will be required to determine exactly which items will be unbundled and shown as separate line items on a customer's bill.

3.2 Current Method of Recovering Costs

In the past, a utility set its rates to recover the revenue required to meet its capital and operating expenditures. Rate adjustments were made through a Commission approved application to Ontario Hydro.

Most utilities recover these costs through a bundled kWh charge for residential and small commercial customers and a combination of kWh and demand charges for larger customers. Some utilities also have a small flat rate service charge representing (1) part of the fixed customer-related component of their costs. The majority of demand meters in use are peak registering only, and the demand charge is based on non-coincident peak demand. In addition, some customers are on time-of-use rates.

The majority of a utility's revenue comes from the kWh energy charge and only a small portion comes from customer demand charges. Many small utilities that have no demand customers over 50 kW obtain their entire revenue stream from kWh energy charges only.

Where service is taken at less than 50 kV, most rates are postage stamp rates in that all customers are charged equally regardless of where they obtain their power from the electric distribution system. Exceptions to this are the rates charged by Ontario Hydro that differentiate customers based on their density, and whether they have single-phase or three-phase service, etc.

3.3 Evaluation Factors

In considering the advantages and disadvantages of various rate structures, the following factors can be considered:

- Ease of implementation (this would include both the initial rate design, availability of data, and changes to billing systems);
- The pricing signal the customer receives in order to encourage the efficient use of facilities and minimize cost to customers over the long term;
- Ease of understanding for customers (including customer perception/salability);

- Stability in utility revenues;
- Stability in rate levels and rate structure for the customer over time;
- Potential cross subsidies;
- Potential for initial rate shock and ability to phase-in any abrupt changes if required;
- How well the rate promotes competition;
- Ease of adjusting the charge if a customer chooses to have a particular service provided by a retailer instead of the LDC; and
- Non-discriminatory.

3.4 Rate Structure for System Losses

Discussion

Ideally, in a given time interval, system load losses should be allocated to each customer based on the ratio of their kVA demand to the sum of individual kVA demands associated with all customers served from the same portion of the system. A reasonable approximation to this would be the integral of the kW demand (which is equal to kWh usage). No-load losses are primarily due to transformer losses and do not vary with a customer's energy usage. However, no-load losses are a small part of the total so the Task Force agreed that it would be reasonable for all system losses to be recovered through a kWh charge.

It is recognized that using a kWh charge as an approximation of a customer's contribution to load losses would result in cross subsidies in cases where the customer's load profile was significantly different than the load profile on the portion of the system they were using. However, given the complexity of trying to determine the load profile of different parts of the distribution system, it was agreed that a fixed charge such as a markup on the spot market energy rate for all customers would probably be more appropriate.

Along this line there was discussion regarding the different contributions customers make to system losses depending on where they are located on the system. This was also discussed in the Retail Technical Panel's (RTP) report to the Market Design Committee. A customer fed from a 4.16 kV system would contribute more to losses than a customer fed from a 27.6 kV system. The RTP recommended that separate loss estimates and rates be developed for customers connected to subtransmission, primary or secondary voltages.

To a certain extent the Task Force agrees with this principle, but also has some reservations. In many cases customers have little choice in selecting their distribution voltage. If a utility has both a 4.16 kV and 27.6 kV line on a given street, a customer should not be penalized if the utility decides to feed the customer from the 4.16 kV system. On the other hand, there are unique circumstances (with some large customers >5,000 kW, for example) where the actual losses attributed to a particular customer can be readily calculated and applied to that customer. A utility may also want to establish a different loss rate for low density rural customers.

As a general principle, the Task Force therefore agreed that where practical, LDCs should be permitted to establish different loss factors for different customer classes. To the extent practical, LDC’s should also be permitted to establish non-discriminatory rates that are unique to individual customers within a customer class.

Although the intent of a system loss factor is to permit the LDC to recover its costs of losses, the Task Force believes that there should be an incentive for LDCs to reduce their system losses. It is recognized that losses can vary significantly from one year to the next due to weather patterns and other reasons beyond an LDC’s control, so any incentive should include a smoothing mechanism. The Task Force recommends that if good data is available, an LDC’s previous five-year average loss factor should be set as the established loss rate during the following PBR period. If losses increase above the five-year average, the LDC would be at risk for the difference, and if losses fall below the average, the LDC could keep the difference as an incentive.

The current Standard Application of Rates to which LDC’s are bound as a condition of the rates approved by Ontario Hydro includes a method for adjusting a customer’s consumption if they are metered on the primary side of a transformer. The adjustment is intended to account for the losses in the transformer. It is recommended that the OEB consider establishing standards in the distribution supply code for the maximum losses that will be permitted for customer-owned transformers. This will promote energy conservation and protect the LDC if a customer-owned transformer is metered on the secondary side.

There was also discussion regarding the option of establishing a per kWh charge or establishing a percentage uplift to the hourly energy usage or energy rate. There was substantial consensus that an uplift charge would be most appropriate since the LDC's costs for losses will vary as the energy rates vary and an uplift charge would attribute those costs more equitably to those customers who use energy during peak times. A per kWh charge could also leave the LDC at risk for fluctuations in the spot market price for the cost of losses if there is no true up allowed for the recovery of losses at the end of the year.

It was also agreed that system losses should not be bundled in with the energy charge in such a way as to make it difficult for a customer to easily compare energy offerings from various retailers. This was countered with the need to avoid potential complexity of the customer's bill and the belief that customers would misunderstand the meaning of system ‘losses’ if losses were shown separately as a line item on the customer's bill.

In the future, system losses will account for a substantial portion of the LDC’s charges to its customers. It would therefore be an advantage to the customer if losses were included in the customer’s energy charge, since the customer would be free to contract with an energy retailer to provide both their energy requirements and their portion of system losses.

It was noted that one of the gas companies currently has a barometric pressure adjustment factor on their bills that adjusts the difference between meter readings to establish a ‘true’ amount of consumption for the billing period. Using this concept, the Task Force had substantial consensus to make the recommendations presented here.

Recommendation

It is recommended that system losses be recovered from a percentage uplift to the hourly energy cost and that both the LDC’s distribution loss factor and the average spot market price be shown on the customer’s bill in the data information section. An example of this is shown in the sample bill presented in Section 3.14.

It is further recommended that initially, system loss factors should be the same for all customers in a given customer class, but if an LDC desired to do so, it could submit a non discriminatory proposal to the OEB to establish varying loss levels for customers based on differences such as geography, voltage level, load profile, load density, and etc.

3.5 Rate Structure for Metering, Meter Reading, and the Billing Cycle

Discussion

There was consensus by the Task Force that all costs associated with a customer's meter and all 'systems' downstream of the meter should be recovered through a flat rate charge on the customer's bill. This would include the purchase, installation, testing and maintenance of meters, meter reading, processing and issuing of bills, account inquiry, collections and a proportional amount of administrative overhead costs.

It is recognized that in the future a customer may be permitted to and may choose to obtain all of these services from a competitive retailer. There was discussion on whether or not this charge should then be a 'pure' charge that would drop to zero if a customer switched all contestable services to a retailer. In theory, this would provide the customer with a clear understanding of the LDC's costs compared to a retailer and would encourage competition. It was noted however that if a customer chose to select a competitive retailer for all of these functions, the LDC would still be required to maintain a number of functions related to settling and recording the activity on a customer's account.

In a related discussion it was also decided that in some cases it may be appropriate to have a flat rate charge for core wires business activities as well (see Section 3.7). If the flat rate charge ends up containing costs other than those purely related to potentially contestable services, the charge would not go to zero if a customer switched all contestable services to a retailer. The final consensus therefore, was that the fixed charge for services downstream of the meter should include not just potentially contestable costs, but all of the LDC's costs related to these services.

At some point in the future, if some or all of these services are opened to competition, it would be important for a customer to fully understand the LDC’s charges for these services. Presumably if a customer elects to obtain some or all of these services from a competitive retailer, they would receive a credit from the LDC. It still needs to be decided, on what basis that credit should be calculated, but once those decisions are made, it is suggested that the LDC publish these credits and make them available to customers so they can compare a retailer’s charges to those of the LDC.

It was noted that customers with different types of metering, or customers who use different payment methods may require different rates.

Recommendation

It is recommended that all of the costs downstream of a customer's meter be recovered through a flat rate charge on the customer's bill. This would include the purchase, installation, testing and maintenance of meters, meter reading, processing and issuing of bills, account inquiry, collections and a proportional amount of administrative overhead costs.

3.6 Rate Structure for Core Wires Business

The Task Force determined that there were a number of alternatives for recovering the costs associated with the core distribution wires business.

Alternative #1 - Kwhr Charge Only

All costs could be recovered through an established per unit rate times a customer’s kWh consumption.

Alternative #2 - Demand Charge Only

All costs could be recovered through a demand charge. This alternative generates a number of sub-alternatives depending on the type of metering the customer has available and the methods used to calculate billable demand:

Interval Meter

Charge can be based on the portion of the customer's demand which is coincident with the LDC's peak, or the charge can be based on the customer's absolute non-coincident peak demand.

Peak Demand Meter

The majority of demand meters in service are peak registering demand meters so the charge would need to be based on the customer's non-coincident monthly peak.

Kilowatt Hour Meter

The wires charge could be based on a flat demand charge based on a previously defined and constant calculated demand, or it could be based on a calculated amount that varies with the amount of energy consumption.

For example, a flat demand charge could be based on the customer's connected kVA (if the data was available), or it could be based on the class of customer, or it could be based on a typical load profile. Alternatively, the demand could be based on the utility's net system load shape and the customer's energy usage for that month. If a customer only has a kWh meter, alternative #2 really becomes either #1 or #3 depending on how the imputed demand is calculated.

Alternative #3 - Flat Rate

Various methods could be selected to calculate a flat rate. For example, the flat rate could be based on the customer's connected kVA (service entrance size), or it could be based on the customer's class (such as a flat monthly service fee for all residential customers).

Alternative #4 - Any Combination of the above Alternatives #1 to #3

The Task Force recognized that various rate classes have different needs and that the most appropriate rate could involve a combination of the methods described in Alternatives #1 to #3.

Discussion

The Task Force also had a number of discussions on the advantages and disadvantages of a pooled rate for distribution charges within a given customer class, versus possibly more customer specific rates. Theoretically a customer's distribution charge could vary by voltage, distance from a transformer station, % coincident usage of a feeder, and so on.

For a large use customer who has an opportunity to self generate or obtain service from a nearby transmission line, an accurate price signal is important. Many large customers are in competition with companies that are directly connected to transmission lines and it is important for distribution charges to accurately reflect their fair share of distribution system usage. Under some circumstances, a pooled price could provide an uneconomic incentive to a large use customer to by-pass the distribution system and become direct customers of the transmission company.

If a LDC has a large rural area, it may want to develop separate rates for lower density customers. If a LDC wanted to apply for rural rate assistance in the future, a separate low density rate would in fact be required.

Beyond establishing a separate rate for rural areas however, the Task Force noted a number of difficulties in trying to develop specific distribution customer rates. If a special rate is permitted for large customers, how would you define a large user, and where would you stop? How would you prevent all customers close to a transformer station from banding together and demanding lower distribution rates? How would you properly allocate the benefit a customer receives from other parts of the network that serve as backup to the customer's feeder? As system configurations change over time due to new loads and feeder changes, should the customer's rates also be dynamic? What methodology could be used to ensure that differing rates were fair and non-discriminatory? Would it be fair to have one rate for a customer fed from a 27.6 kV feeder and another rate for a neighbouring customer fed from a 4.16 kV feeder if the customers had no choice in the selection of their distribution voltage?

Despite these difficulties, the Task Force felt that LDCs should be free to propose customer specific cost allocation methodologies in the future if they wished to do so, as long as these methodologies align with the principles outlined in section 3. This is most likely to be applicable to large customers given that many LDCs have only one large customer and others have only a few. Such arrangements may take the form of a connection agreement between the large customer and the LDC. This can include the obligation of the LDC to make connection to the distribution system available and the obligation of the large customer to provide a minimum revenue and the contract period it would apply to. Such an arrangement may be appropriate when a large customer is requesting an increase in service that requires new investment by the LDC. Some members of the working group consider that each large customer should be able to request that a customer specific rate be developed provided the customer covers the cost of the study.

In the meantime, the Task Force recommended that a simplified method be approved by the Board that LDCs could use for establishing their initial rates for wires charges for different classes of customer. The method recommended by the Task Force is discussed in Section 3.15 of this report.

3.7 Residential and < 50 kW General Service Rates (kWh meter only)

Discussion

A number of alternatives are available to recover distribution costs from residential and general service customers who do not have demand or interval meters. As a first assumption, the Task Force assumed that any customer who obtains an interval meter or has a demand meter would be treated differently than those with only standard kWh meter. (see Sections 3.8 and 3.9) The discussion in this section covers those customers who are serviced with a kWh meter only.

For residential and smaller general service customers there are many competing needs. For example, the desire to provide customers with appropriate price signals needs to be balanced with the need to keep rates simple. Any change in rate structure also needs to consider the impact the change would have on both high and low use customers and the effect this would have on a customer's perception about the consequences of deregulation.

After much discussion there was a consensus that there should be a minimum charge for all residential and small general service (< 50 kW) customers to recover some minimal level of distribution service. The premise is that once a system is built and a service is connected, there is a level of sunk costs that should be recovered regardless of the customer’s energy usage.

In conjunction with the preceding, there was also discussion as to whether a fixed rate should be assessed based on a customer’s connected load or service size. This would provide a very stable revenue stream for the LDC. However, it was noted that it would be very difficult to initially obtain and then maintain the data required to ensure that all customers with the same service size were treated equally. A flat rate based on a customer's service size would also penalize customers who plan ahead and install larger services than necessary to accommodate future growth. A further problem with the flat rate charge is that very large customers in the same rate class end up not paying their fare share for the proportion of system capacity they use. Despite these disadvantages, this structure received considerable support from some members of the Task Force because of its simplicity.

One of the other problems identified with any type of flat rate service charge was the effect this could have on very low energy use customers. If a fair flat rate wires charge was added to the charge already described for services downstream of the meter, low use customers could be faced with a significant hike in unavoidable minimum charges.

It is interesting to note that at a recent OEB hearing on rates for Enbridge Consumers Gas, intervenors argued that increasing the monthly fixed charge and decreasing the per unit delivery charge would reduce the incentive to conserve. It was also argued that an increase in the monthly charge would have a greater impact on low consumption (and possibly coincidentally lower income) households. Currently, the fixed monthly charge levied by Enbridge Consumers Gas is designed to recover approximately 50% of customer fixed costs and the remaining costs are recovered through the delivery charge.

There was some debate as to whether a flat kWh charge only would be an appropriate way to recover the revenue required to maintain the distribution system. It was noted that this would tend to be unfair to average and larger customers since they would be paying proportionally more for their wires service than a very low user even though both required some level of minimum investment to receive service.

A straight kWh charge could also pose a risk to the LDC in some communities if a large number of customers switch from electric to gas heat or if distributed generation begins to take hold. The LDC would lose revenue but still need to support the sunk cost of the distribution system. This is based on the assumption that once a price cap has been set for an LDC's wires charges, the LDC will be at risk for recovering its wires charges and will not be permitted to form a true up at year end unless there is an unusual event that qualifies as a 'Z ' factor.

Along this line it was suggested that rather than either a flat rate or straight kWh charge, it might be appropriate to recover the cost of a minimum wires system through a kWh charge that itself had a minimum level. This would ensure a minimum revenue even from very low users and would avoid having a large, flat rate charge standing alone on the customer's bill. A minimum amount on the kWh charge would accomplish the same purpose as a flat rate charge, but some members felt that the presentation would be more acceptable.

A wires charge based at least partially on kWh consumption has the advantage that large customers in a rate class pay a fairer share for the system capacity they use. There would still be some potential for cross subsidies if a customer's load profile differed from the net system load shape, but this would be true of any rate structure unless an interval meter was installed and used to properly allocate costs. For customers with a favourable load profile, there will always be an incentive to purchase an interval meter and this should ultimately promote competition and a more efficient use of the electric system.

It was also noted that any type of charge based on kWh consumption as opposed to a flat rate would encourage energy conservation.

In order for a minimum kWh charge to be effective, it was pointed out that the charge would need to be calculated and shown separately from the energy charge. Otherwise, at low usage rates the proportion of the charge due to energy could frustrate the collection of the minimum wires charge. Some members felt that separating the charge out would unnecessarily complicate a residential bill and therefore favoured a flat rate charge only.

Recommendation

It is recommended that a component of distribution costs (based on some minimum level of distribution service) be recovered from all customers through a

i. flat rate monthly charge; or a
ii. kWh charge with a stated minimum; and

that remaining distribution costs be recovered through a kWh charge.

It is also recommended that LDCs be permitted to design rates that are appropriate for their types of customers based on the principles stated in Section 3.3.

3.8 General Service Customers > 50 kW (with demand meter only - no interval meter)

Whenever a demand meter is available, the distribution wires revenue should be collected by way of a charge based on the customer's non-coincident peak. If the customer is equipped with a kVA meter, the actual kVA reading should theoretically be used.

If a customer only has a kW meter and no kVA meter, the kW reading will need to be adjusted to approximate the kVA demand. One alternative is to calculate a charge based on the kW reading adjusted to assume a 90% power factor (kW divided by .90). This would have the effect of penalizing customers with good power factor. If this method was chosen and if a customer wanted to pay a charge based on their actual kVA load, they could pay to have a kVA meter installed. As the LDC installs new kVA meters in the future, this alternative has the advantage in that there would be no sudden rate impact for the customer.

Another alternative is to assume a 100% power factor and use the kW reading directly as the kVA reading. This alternative does not penalize customers who have maintained a good power factor but has the disadvantage that in the future, when the LDC decides to install a kVA meter, the customer could experience a significant rate increase.

Lastly, a compromise between these two alternatives would be to select a power factor between 90% and 100% and adjust all the kW readings accordingly. The LDC could also select a different adjustment factor for different types of customers.

Either one of these alternatives is acceptable to the Task Force. The basic recommendation is that the wires charge should be based on the customer’s non-coincident peak regardless of what time of day it occurs.

The Task Force also noted that newer electronic meters have a number of options for calculating billing demand. For example, the demand could be calculated on a 5-minute basis, a 15-minute basis, rolled or fixed periods, etc. At this point in time, the Task Force recommends that the guidelines provided in the Standard Application of Rates continue to be used.

It is also recommended that in the future all new customers should be equipped with kVA meters.

3.9 Customers with Interval Meters and Large Use Customers

It was agreed that the same principles discussed in Sections 3.6 and 3.8 above should apply to all customers with interval meters including existing large use customers. It was noted that some interval meters consist of an electronic package added to an existing mechanical kWh meter and that an imputed demand would therefore need to be calculated for some types of meters.

3.10 Transmission Charges

Although there are some similarities between transmission and distribution systems in that both need to be built to meet peak capacity demands, there are also significant differences. Distribution investments are considerably less lumpy than transmission investments. In theory, a price signal that encourages a customer to reduce demand should ultimately reduce capacity requirements in both distribution and transmission systems. However, once a line has been built, as long as sufficient capacity is available, a reduction in a customer's demand would only reduce the revenue available to recover the sunk cost. This problem is more apparent in transmission systems than in distribution systems because of the long lead times and lumpy investments required for transmission.

However, the problem of how to recover transmission costs from wholesale customers is outside the mandate of this Task Force. The Task Force assumed that it is likely that LDC's will be charged for transmission services based on the LDC's peak monthly demand. Once a transmission rate is set, LDCs will need to estimate their monthly peak demands and set an appropriate rate to try to recover that cost as equitably as possible from all customer classes and customers within a class.

The LDC collects the transmission charge as a pass-through of the transmission charges administered by the IMO. The ideal would be to pass through the charge in exactly the same form as the charge is applied to the LDC. This would allocate each customer its appropriate share of the transmission charge and minimize the exposure of the LDC to financial risk. Ideally, the transmission charge should also be passed on to a large customer on an LDC's distribution system in the same way that these charges will be levied to large users on the transmission system. It should be possible to get close to this ideal for interval metered customers but it is pointed out that this could mean two different demand charges for each customer. One demand charge would be based on non-coincident peak to recover distribution wires charges, and the other demand charge could potentially be based on the customer's peak that is coincident with the LDC's peak in order to recover transmission charges.

At this point in time, until more is known about how the transmission charge will be levied for LDC's, the Task Force recommends for simplicity, that the transmission charge be based on a customer's non-coincident peak. For customers without demand meters, it will likely not be possible to exactly match the form of the transmission rate, so it is recommended that a kilowatt hour charge should be levied based on an imputed demand calculated using an individual customer load factor determined for each customer class.

Because the transmission costs are meant to be a pass through for the LDC, it is also recommended that LDCs should establish a process to true up these costs on a yearly basis. Rates could be established annually and a variance account could be used to carry forward any shortfall or overcharge from the previous year.

Based on these assumptions, the Task Force agreed to make the recommendations presented here.

Recommendation

It is recommended that transmission and IMO charges should be shown separately from LDC charges on the customer's bill in order to clearly separate the costs that an LDC is responsible for from costs that are beyond the LDC's control.

If a customer has a demand meter, the transmission charge and any demand based costs imposed by the IMO should be recovered from a demand charge based on a customer's non-coincident monthly kVA peak (or adjusted kW peak as discussed in Section 8).

If only a kWh meter is available, a per kWh charge should be levied based on an imputed demand calculated for each customer class.

In order to determine how the transmission and IMO charges should be passed through to customers who have interval meters, further information is required on exactly how these charges will be billed to LDCs.

The LDC should establish rates on a yearly basis in order to recover all of the charges imposed by the IMO and establish a process to true up these rates on a yearly basis in order to accommodate any shortfall or overcharge in the previous year.

3.11 Backup and Standby Charges

In any situation where system capacity needs to be reserved for use by a customer without notice, the Task Force agreed that wires charges should apply.

An example of this would be a 5 MW customer who installs a 4 MW cogeneration unit and wants to maintain a backup or standby supply in the event their cogeneration unit trips off-line or is unavailable. Although on a normal day, the customer's load would register only 1 MW of peak demand, the wires charge should be based on 5 MW - the total standby capacity required.

Using the same example, if a customer is able to demonstrate that through load rejection schemes or other methods they do not require the full 5 MW capacity as backup, the utility would be able to negotiate a wires charge based on the most realistic load that would be required.

In order to encourage customers to be realistic in their estimate of how much backup or standby capacity they require, some utilities in the past have designed a penalty in their backup rate. Continuing with the same example, if a customer demonstrated that they only required 3 MW of backup capacity, they would be charged a penalty if they used more than 3 MW in any given month. One example of such a penalty is a requirement that if a customer exceeds their agreed upon backup capacity allowance, they must pay 150% of the actual demand used for the following 6 months. Another way to ensure realistic charges is to always calculate the backup wires charge based on a customer's previous peak demand (firm power requirement plus generator capacity) over a rolling 12-month period.

A backup or standby charge would also apply to customers who have preferred and alternate feeds if they have the ability to transfer their load without notice.

3.12 Generators within an LCD's Service Territory

The Task Force agreed that generators should be exempt from paying any wires charge for use of a LDC's distribution system unless the system required upgrading, in which case a capital contribution may be more appropriate.

Ultimately, all energy users must pay a wires charge for their use of the distribution system and if a wires charge was also levied against generators, it could be argued that the wires charge would end up being collected twice. It would also be very difficult to determine what portion of the distribution (and transmission) system a generator was actually using.

Once a price or revenue cap has been set for a given LDC, a rate for the wires charge will be developed to collect the appropriate amount of revenue from the customers within the LDC's service territory. Whether or not generators are included in the group of customers who pay the wires charge is simply a cost allocation issue. Collecting the wires charge from users only and not from generators will simplify the accounting for load displacement generators and should also help to encourage competition in generation. The Task Force therefore, agreed that generators should be exempt from paying any distribution wires charge.

3.13 Street Lighting and Other Unmetered Loads

In keeping with the earlier recommendation that LDCs should be free to propose customer specific cost allocations, it is recommended that the wires charge for street lighting or other unmetered loads should be based on a calculated kVA demand based on the actual known load profile.

It would also be appropriate for LDCs to develop specific customer charges for its various types of unmetered load to reflect the actual cost of estimating and preparing the bill and handling the account.

3.14 Sample Bills

Residential or General Service Customers who only have a kWh Meter							
Previous Reading	Current Reading	Billing Multiplier	Metered KWh Consumption	Distribution Loss Factor	Transmission Price	Distribution Price	Weighted Average Spot Market Price
5200	6100	1	900	1.031	$0.0117/kWh	$0.011/kWh	$0.038/kWh

Monthly Service Charge ………………………………………………	$14.50
Competition Transition Charge (CTC) ……………………………….	TBD*
Independent Market Operator Charge (IMO)………………………….	TBD*
Transmission Charge *(900 kWh x $0.0117) ………………………..*	$10.53
Distribution Charge *(900 kWh x $0.011) ………………………...*	$ 9.90
Energy Charge *(900 kWh x 1.031 x $0.038)………………..*	$35.26
Total	$70.19 + TBD*

The LDC could choose to show the detailed calculations as indicated in italics or provide a generic description of how the calculation is made on the back of the bill.

* To be determined

Customers with a Demand Meter								
Previous Reading	Current Reading	Billing Multiplier	Metered KWh Consumption	Demand KvA Reading	Distribution Loss Factor	Transmission Price	Distribution Price	Weighted Average Spot Market Price
52021	58525	10	65040	152	1.031	$4.20/kVA	$5.80/kVA	$0.038/kWh

Monthly Service Charge	$17.50
Competition Transition Charge (CTC)	TBD*
Independent Market Operator Charge (IMO)	TBD*
Transmission Charge *(152 kVA x $4.20)*	$638.40
Distribution Charge *(152 kVA x $5.80)*	$881.60
Energy Charge *(65040 kWh x 1.031 x $0.038)*	$2,548.14
Total	$4,085.64 + TBD*

* To be determined

Customers with an Interval Meter							
See the attached data sheets for detailed hourly usage and energy price data	Sum of the Product of Hourly Energy Price x Hourly Energy Usage =	Total kWh Consumption in Billing Period	Demand kVA Reading	Distribution Loss Factor	Transmission Price	Distribution Price	Average Hourly Spot Market Price
	$2,406.48	65040	152	1.031	$4.20/kVA	$5.80/kVA	$0.027/kWh

Monthly Service Charge	$17.50
Competition Transition Charge (CTC)	TBD*
Independent Market Operator Charge (IMO)	TBD*
Transmission Charge *(152 kVA x $4.20)*	$638.40
Distribution Charge *(152 kVA x $5.80)*	$881.60
Energy Charge *($2,406.48 x 1.031)*	$2,481.08
Total	$4,022.18 + TBD*

* To be determined

3.15 Interim Rate Unbundling Methodology

There is an on-going expectation that retail open access will emerge during the year 2000. To prepare for this event LDC's will be required to unbundle the rates they currently charge customers to promote retail access and facilitate choice. The problem most LDC's will face is an immediate lack of resources and time to perform a cost of service study that would be required to accurately reflect or implement the recommendations contained in this report. Therefore, the task force is recommending that the LDC's be allowed to continue with rates based on the average cost of service and cost allocation model used by Ontario Hydro to set LDC rates in the past.

Recognizing this shortcoming the Task Force has developed a simplified rate unbundling method which separates the cost of providing distribution and related services from the cost of energy and transmission (wholesale costs).

The model process flow and an example are presented in Figure 3.15.1 and Table 3.15.1. A number of principles were considered to recognize this process as an interim solution only:

- The resulting rates should, to the extent possible, provide customers a smooth transition to open access. To accomplish this, customer revenues at existing rates are unbundled by removing the wholesale cost of power. The premise is that class cross subsidies will remain in the short term until an unbundled cost of service study is developed to support the required change. Another assumption is that wholesale cost of power approximates the price customers will pay when subject to spot market price pass through and the transmission tariff. Once these prices are better understood, the cost of providing these services at the class level could be substituted for the current wholesale cost. This would further reduce the initial impact on customer bills.

- The process should be simple to apply and minimize the number of estimates required.

- Data requirements should come from currently available sources or soon to be available sources.

In addition the form of the resulting rates should be consistent with the direction recommended in the body of this report.

Figure 3.15.1
Interim Process to Develop Unbundled Dx Rates

Step 1: Determine Dx Revenue by Class

	Revenue		Cost of Power		Dx Revenue
Residential	Known	-	Unknown	=	Unknown
General Service	Known	-	Unknown	=	Unknown
Large Users	Known	-	Unknown	=	Unknown
	Known		Known		Known

Step 3: Design Unbundled Rates (e.g. residential)

(1) **Variable Dx Rate (¢/kwh)** = (End Rate IDC - Losses) * Some Variance
(2) Energy Based Dx Revenue = Variable Dx Rate * kwh in class
(3) Fixed Rate Revenue = Class Revenue - Energy Based Revenue
(4) **Fixed Rate ($/Month)** = Fixed Rate Revenue / Class customers

(Loss Rates need to be estimated = cost of losses / delivered energy)

Step 2: Determining Customer Class COP

A) **Allocate Utility Volumes**

LU Volumes
(direct assignment,
from the data we have)

General Service & Residential
(Utility - Large User)

General Service

Residential

B) **Class COP** = **Class Volumes** (WP/SP kW, WP/WOP/SP/SOP kWh) * **Utility Rates** (Wholesale Rates)

Data We Have

- Utility WP/SP kW, WP/WOP/SP/SOP kWh
- Large UserWP/SP kW Coincident with Utility Peak, WP/WOP/SP/SOP kWh

Data We Need to Estimate

- GS kW Coinc with Utility * Loss Factor
- Residential kW Coinc with Utility * Loss Factor (can be estimated using Generic Cost of Service Data or NSLS)
- GS kWh by Period * Loss Factor
- Residential kWh by Period * Loss Factor
- Loss Factor (estimated as difference between energy purchased and accrued billed energy)

Principles:
- Bill Impacts, hold class revenues constant
- Minimize the number of estimates required and impact
- Use available data or soon to be available (eg. Generic CoSS, NSLS)

Table 3.15.1
Unbundled Distribution Rates

1) Determine Dx Revenue by Class

	Revenue (Input)	Revenue Adjust (Input)	Cost of Power (Calculated)	Distribution Revenue
Residential	10,634,495	0	8,858,598	**1,775,897**
General Service	20,095,977	0	18,244,782	**1,851,195**
Large Users	2,935,684	0	3,018,898	**-83,214**
Streetlights	145,768	0	142,433	**3,335**
Subtotal	33,811,924	0	30,264,710	**3,547,214**

Adjusted for Other Class Revenue (Late payments, rentals, etc.)

2) Class Cost of Power

Volumes (input)	**WP kW**	**SP kW**	**WP kWH**	**WOP kWH**	**SP kWH**	**SOP kWH**	**Total kWh**	
Residential	161,709	118,857	38,319,753	37,087,735	31,105,023	30,313,993	136,826,505	
General Service	256,284	276,106	81,376,477	73,445,326	75,752,381	62,586,400	293,160,583	
Large Users	42,883	38,919	13,554,232	12,007,111	12,672,837	12,433,782	50,667,961	
Streetlights	3,569	605	450,965	1,066,939	202,242	894,990	2,615,136	
Sentinel Lights	0	0	0	0	0	0	0	
							483,270,185	
Rates(Input)	12.05	9.02	6.09	3.35	5.03	2.3		
Cost of Power							**Total $**	$/kwh
Residential	1,948,593	1,072,089	2,333,673	1,242,439	1,564,583	697,222	8,858,598	0.06474
General Service	3,088,224	2,490,481	4,955,827	2,460,418	3,810,345	1,439,487	18,244,782	0.06223
Large Users	516,741	351,045	825,453	402,238	637,444	285,977	3,018,898	0.05958
Streetlights	43,010	5,459	27,464	35,742	10,173	20,585	142,433	0.05446

3) Simplified Rate Design

	Residential			**General Service**
Wholesale kWh	136,826,505		Wholesale kWh	293,160,583
Loss Factor %	4.09%		Loss Factor %	4.09%
Retail kWh	131,453,349		Retail kWh	281,648,212
IDC	0.00620	<---- $/kwh ---->	IDC	0.00620
Loss Rate	0.00265	<---- $/kwh ---->	Loss Rate	0.00254
Variable Dx	0.00355	<---- $/kwh ---->	Variable Dx	0.00366
Variance	0%		Variance	20%
Variable Rate	**0.00355**	<---- $/kwh ---->	**Variable Rate**	**0.00439**
Dx Revenue	1,775,897		Dx Revenue	1,851,195
Variable Rev	467,135		Variable Rev	1,235,699
Fixed Rev	1,308,762		Fixed Rev	615,496
Customers	9,115		Customers	1975
Monthly Fixed Rate	**11.97**	<---- $/Month ---->	**Monthly Fixed Rate**	**25.97**

Three fundamental steps are employed to split the existing rates.

Step 1

The first step is to determine customer class revenue at existing rates. All LDC's have this data readily available. LDC's customer class revenue should be reflective of a calendar year (or at least match the timeframe to which the volumes are applied) and should only represent the energy sales portion of utility revenues (i.e. should be net of water heater rentals, late payment charges, etc.).

Step 2

The second step is the derivation of wholesale costs by customer class. It is unlikely that utilities will have all the data required to perform this operation. Taking billed quantities (from utilities wholesale power invoices) and allocating these to the classes based on historical load research can derive estimates of class volumes. Such load research data is available for the 1980's.

The task force recognizes that this information is dated but is the best information available at this time. Another approach to this step, which will likely be available as we near open access, is for the utility to develop net system load shapes (or using the method dictated by the retail market rules) or actual load shapes for interval metered customers. Forward price curves can then be used to estimate spot market prices. The utility's cost of transmission service can also be allocated to classes based on the load shapes.

Once calculated, this amount can then be subtracted from the total class revenues from step one with the remainder representing an estimate of distribution (and related services) revenue. Although the process in the attachment does not show this, any board approved changes to a utility's revenue requirement (e.g. transition costs, changes to rates of return, etc.) could be allocated to the class distribution revenues. This assumes that these revenue requirement changes are related to the LDC business.

Step 3

Step three is the development of rates that recover the utility's distribution revenue requirement as established in step 2. Following on the recommendation that the distribution rates should comprise both a fixed and variable component this step starts by using the existing incremental distribution cost (IDC) currently embedded in utility bundled rates ($0.0062/kWh).

The Task Force recommends that distribution losses be recovered by applying a markup (distribution loss factor) to customers metered kilowatt-hours and multiplying the product by the spot price. Therefore, since the IDC includes the recovery of losses an estimated amount must be removed. A per kilowatt hour cost (variable) can be calculated from the result of step 2 and used to calculate an IDC net of losses. A fixed charge can then be calculated simply as the remainder of total distribution revenue requirement less the amount recovered from the variable unit cost (net IDC) on a class by class basis divided by the number of customers (average) in the class.

Finally unbundled rates can then be developed based on the unit costs and employing some level judgement (guideline variance to reflect utility policy, mitigate individual customer impacts – low versus high usage, etc.).

A sample spreadsheet illustrating how these calculations can be made is presented in Appendix A.

3.16 Pricing Flexibility

3.16.1 Background

When regulating through a price-cap mechanism, the degree of pricing flexibility for the utility must be addressed. One overall price cap that controls average prices may be unsatisfactory if it results in a mix of high and low rates that offset one another. As an alternative, customers can be grouped together into baskets, with a price cap set for each basket. The utility then has the flexibility to adjust rates within each basket provided no basket, on average, exceeds its price cap. The question then to be addressed is -- How many baskets are reasonable?

3.16.2 Customer Classes

Presently, most utilities have three main customer groupings: residential, general service, and large user for customers greater than 5 MW. During the initial stages of PBR, it will be a difficult and imprecise task for most utilities to separate out and identify their distribution wires costs for each of these classes.

Using the approach described in Section 3.15, utilities can roughly allocate the cost of power to each customer class. Then, by assuming that distribution (LDC) revenues for each class should remain neutral, a cost allocation by class can be imputed. However, accurate cost allocations to each class can only be carried out when a proper cost of service study can be conducted, together with the establishment of a proper system of accounts to track costs. Therefore, the introduction of numerous new baskets for the first generation PBR will prove too onerous for most utilities and likely could not be supported with meaningful data.

However, three customer classes are also not sufficient. The extreme variability in consumptions and the different metering available in the General Service class, suggest that this class should be subdivided into probably three groupings based on size:

1. Less than 50 kW
2. 50 kW to 1,000 kW
3. 1,000 kW to 5,000 kW

Furthermore, unique characteristics of a particular utility may suggest other sub-groupings. For example, both Residential and General Service classes could be split along a rural/urban classification in those utilities serving larger rural areas.

Therefore, the LDC should have some discretion in determining the final number of customer classifications it will require. The LDC will need to balance its own unique characteristics against its ability to allocate costs in a meaningful way, at least during the first generation PBR.

After the first generation PBR scheme has been established and the LDCs become more comfortable and adept at tracking costs, further levels of sophistication can be added. LDCs will understand their distribution costs better and how these costs relate to each customer class. Also, by that time a competitive market and culture will have developed. Additional flexibility may therefore be required when the second generation of PBR takes effect.

At that time, further baskets may be defined as subgroups of customers with homogeneous characteristics are re-defined which in turn will require greater pricing flexibility.

3.16.3 Flexibility within a Basket (i.e. Customer Class) and Between Baskets

Using the initial rate setting method described in Section 3.15, a LDC will be able to calculate the total wires revenue that needs to be collected from each traditional customer class. If the LDC then wishes to create additional baskets within that customer class, what rules should apply?

It is suggested above that a LDC may wish to create three pricing baskets within the general service class. The Task Force recommends that in the first generation PBR, pricing flexibility between baskets within a traditional customer class should be restricted to ± 15% of the calculated rate. It is also recommended that any pricing adjustments within a basket be applied uniformly across all customers within that basket. If a LDC wishes to apply pricing flexibility to a single customer within a basket (for example, to encourage a customer to remain connected to the distribution system), that should only be permitted through specific application to the OEB. The initial creation of baskets within a traditional customer class should also be approved by the OEB.

An LDC could therefore propose baskets within the general service class and adjust the rates ± 15% for any basket as long as the total revenue for the LDC does not increase. For example, an LDC may find that most of its less than 50 kW general service customers are small retail customers in the core area of the community. In order to encourage retail growth, the LDC's Board of Directors would be permitted to lower the wires charge for all customers within this basket by up to ± 15%. If the basket of customers represented 30% of the revenue that the LDC received from its general service class, the monthly service charge and/or the distribution charge for the less than 50 to 1,000 kW customers and the 1,000 to 5,000 kW customers could be raised proportionally to maintain the total revenue neutral.

This flexibility should also be permitted between customer classes using the same principle of 15% maximum flexibility as long as total revenues do not increase. For example, if a utility believes that there are cross subsidies between its customer classes, this pricing flexibility would allow it to start moving its prices in the appropriate direction. A utility specific cost of service study would need to be submitted to the OEB to support any changes greater than ± 15% for the base rate calculated using the method proposed in Section 3.15.

As PBR runs its course, the LDC's price cap will be adjusted each year, and each year, the LDC should be permitted to make total revenue calculations for each basket of customers so that the price adjustments can be applied. An overall decrease of 1% in the LDC's price cap for example, could be applied non-uniformly to any basket or group of baskets as long as the rate change for any individual basket is 15% or less in a given year and as long as total revenues (based on the customer mix at the time) are calculated to decrease by 1%.

3.16.4 Contestable Services

Sections 3.16.1 to 3.16.3 pertain to the core wires business. Each LDC will also be carrying on a number of core activities that may eventually be contestable in the marketplace. The provision of certain activities such as billing and collecting, meter reading, meter services and possibly some fringe services may be subject to competition and customer choice. If an LDC takes the position that it wishes to compete in these markets, it will require some degree of pricing flexibility as soon as these services become contestable.

Each contestable service within each customer class would then require a separate basket. The LDC must allocate its costs to each of these baskets based on cost causality.

Costs that can be directly attributed to each basket should be identified first. Secondly, indirectly attributable costs would be assigned using a reasonable basis for allocation. This total would then represent ‘floor prices’ for each of the contestable services. When these are compared to outside markets, they would also indicate where a utility may or may not be competitive.

The issue then becomes one of assigning all remaining non-attributable costs (e.g. some general & administration costs, interest, etc.). If the price-cap for each basket is considered the ‘ceiling price’, the LDC could then allocate the total non-attributable costs to each basket based on the room available and also with due regard to any market based prices that may be available.

4. IMPACT OF MARKET-BASED RATE OF RETURN AND TAXES ON REVENUE

A spreadsheet was developed to analyse the potential impact of market-based rate of return and taxes on revenue requirement. The analysis was conducted on 1996 data from the Municipal Utility Databank (MUDBANK) for all Municipal Electric Utilities (MEU). The dollar value of total assets is used to define risk class based on the guidelines set out in Dr. William Cannon's December 1998 discussion paper. A utility's risk class determines its capital structure. The components of capital structure include the common equity ratio (CER), allowed return on equity (ROR), debt ratio and debt rate. The values for these ratios applied to the utilities were taken from Dr. Cannon's report. The allowance for capital taxes used is 0.525% representing both the provincial and federal portions of capital taxes. These inputs were used to calculate the overall return on rate base before tax. Allowed return (dollars) is the product of the rate of overall return by rate base.

4.1 Rate Base Determination

Utilities are allowed to earn a return on investment made to provide regulated services. The term rate base is used to identify the appropriate level of investments necessary to provide that service.

The rate base is the average investments required over period of a year to provide the regulated services. Generally, the rate base includes two main components: long term and short term investments.

Long term investments include capital expenditures at original cost less accumulated depreciation (net fixed assets). Typically any contributions or grants provided to the utility by the customer are subtracted from long-term investments as the utility has not provided the money for these investments.

Short term investments are included in the rate base under the category of working capital allowance. Working capital allowance includes: inventory (materials and supplies), prepaid expenses, customer security deposits (acts as offset) and a working cash allowance.

The working cash allowance reimburses the utility for the carrying cost on the cash flow needed between the time the service is rendered until it is paid for by the customers. The components of working cash allowance would include: cost of power for standard supply; operations/ maintenance/administrative expense; capital tax and goods and services tax. A monthly average cost is calculated for these items. The working cash allowance is the product of monthly average costs by the net lag days. Net lag days is the number of days between the time service is rendered and the time service is paid for by the customer.

As a starting point, the analysis used a one-month time lag for all items in calculating the working cash allowance. The committee recognized that this may not be entirely appropriate and that more information is needed from the IMO with respect to the timing of the payment of the transmission charge. In addition, customer deposits and prepaid expense data is not available from the MUDBANK data and therefore is not included in the analysis. There was also some discussion as to whether some standard should be applied for inventory levels as they vary widely among utilities.

4.2 Impact on Service Revenue and Wires Revenue

The allowed return was calculated as a percentage of 1996 service revenue (distribution plus cost of power). In order to assess the impact of contributed capital in the rate base two scenarios were generated: contributed capital in rate base and contributed capital excluded from rate base. A comparison was then made to revenue under rate of return prior to Bill 35 (existing structure). The impact analysis was also conducted on wires revenue (distribution only), defined as gross margin on energy sold.

The per cent impact of market based rate of return and taxes on total utility revenue (distribution and wholesale cost of power) and on distribution (wires) revenue only using 1996 MEU data with and without contributed capital in the rate base is summarized for all utilities in Table 1.

Table 1

Impact (%) of Market-Based Rate of Return and Taxes on Revenue

	% Impact on Service Revenue	**% Impact on Wires Revenue**
Contributed Capital in Rate Base		
Minimum Utility Impact	**-3.2**	**-18.7**
Maximum Utility Impact	**19.6**	**194.0**
Average Utility Impact	**6.1**	**49.0**
Contributed Capital out of Rate Base		
Minimum Utility Impact	**-5.1**	**-29.9**
Maximum Utility Impact	**18.7**	**179.9**
Average Utility Impact	**4.0**	**32.9**

5. RESTRUCTURING COSTS

In discussing the LDC's costs related to restructuring requirements, the Task Force came up with the following list:

1. Incremental and displaced staff costs related to restructuring, both internal staff and external consultants (e.g. financial staff, tax specialists, regulatory staff).
2. Consultants for valuation of rate base (e.g. for sale of MEU, for property tax determination).
3. Accounting system to accommodate new unbundled uniform system of accounts.
4. Billing system to accommodate unbundled distribution rates, supply settlements, customer transfers between retailers, etc.
5. Business plan related to restructured business (external consultant's costs).
6. Meeting IMO requirements (e.g. metering and communications).
7. Structural/physical separation of businesses (distribution vs. retail supply).
8. Costs associated with incorporating (e.g. legal, consulting).
9. Licensing fees.
10. Cost of customer education and public relations related to restructuring.
11. Working capital requirements.

The members on the four PBR task forces representing LDC's were asked to provide cost estimates for each of the restructuring costs identified by the Distribution Rates task force. Thirteen responses were received. The total cost estimated by these LDC's ranged from $270,000 to $7,180,000, with average total cost at about $2,500,000. The highest cost item for most of these utilities is forecasted to be the new billing system.

From discussions with some small LDC's (<5,000 customers), it is felt that $25-75,000 is a reasonable estimate of costs for small utilities. It is important to note that these costs would primarily apply to items #1, #3, #6, #8, and #9 from the list above.

There was considerable comment made on the issue of capping LDC spending on transition activities. This topic is a management issue but becomes a public policy issue given the type of funds being used (public) and the nature of the fund approval process that most LDCs follow (not return based). This brought up the issue of justification requirements for restructuring costs.

It is clear that costs need to be incurred to meet the intent of Bill 35. However, how do costs associated with the investigation and pursuit of competitive business opportunities get handled when the only source of funding is the regulated rate base? There is an equally large issue related to spending on systems (e.g. Settlement and Billing) that may not be justified given a set of competitive business rules (e.g. Positive NPV discounted @15%).

This requires Board guidance given the nature of the issue.

Other issues that required further guidance include the following:

- Load Control Systems
    - The issue of how to treat load control systems under PBR was raised specifically dealing with Hot Water Tank load control that is currently used for peak shaving. The value of this feature to the LDC under PBR must be decided
- Affiliates
    - When is an affiliate required in order for a utility to supply fringe services?

  - There are numerous PUCs in Ontario. The issue of how to treat the "waterworks" must be discussed.
- The lists of Contestable and Fringe Services need to be reviewed to ensure they are complete.
- How are credits for switching the supplier of Contestable Services calculated?

6. TREATMENT OF CONTRIBUTED CAPITAL

This section is organized as follows:

Background on the regulatory treatment of contributed capital under Ontario Hydro's regulatory authority is presented in Section 6.1. This section also summarizes the Task Force's discussion on contributed capital. Options are then presented on the treatment of contributed capital taken by the LDC's under Ontario Hydro's regulation. However, while a recommendation on the options is provided, the discussions at the Task Force's subsequent meeting indicated a lack of consensus on the recommendation. Therefore in Section 6.2, a summary of the various positions among the participants on the treatment of contributed capital among the Task Force participation is presented. Individual position papers from Task Force members are presented in Appendix A (Econanalysis Consulting Services) and B (Nepean Hydro).

In Section 6.3 the Board's current considerations as to when contributed capital should be collected by the gas utilities is described.

6.1 Background and Options

In examining the issue of treatment of contributed capital with regard to rate base, it is necessary to first have an appreciation of the history of contributed capital. The concept of contributed capital originated in the 1960's when customers started asking for underground distribution because they wanted the unsightly poles and wires buried. It was argued then that the customer receiving this aesthetic value should contribute towards the cost. As a result, existing customers= rates did not increase and the customers receiving the added benefit paid for it separately. As well, the contributed capital did not form part of the utility=s rate base on the rationale that the utility should not earn a rate of return on contributed capital.

The accounting treatment for contributed capital at the onset was to record it as part of gross assets and part of equity. There was no amortization of contributed capital. The accounting treatment of contributed capital changed starting in 1980 when Ontario Hydro prescribed that assets financed by contributed capital would continue to be added to gross assets but that a separate liability account (#375) would be used on the equity side of the balance sheet to record the contributed capital. And, the contributed capital shown in the liability account began to be amortized and appeared as a reduction to depreciation expenses. All contributed capital received up to December 31, 1979, remained in the equity section of the balance sheet and appeared as Acontributions prior to 1980@. This amount continued to remain unamortized after 1979. As well, assets financed through contributed capital continued to be excluded from the rate base for purposes of calculating the return on assets.

Utilities had no difficulty with the concept of having contributed capital excluded from the rate base because utilities= returns were below the maximum allowed by the regulator. However, in the 1980's some utilities began experiencing sustained growth or experienced premature failure of underground cables and began bumping up against the rate of return limit. The outcome of this phenomenon was that the regulator approved a change to the treatment of contributed capital. In its 1994 Revenue Limiting Criteria and Retail Rate Guidelines for Municipal Electrical Utilities, Ontario Hydro stated the following:

- Assets financed by contributed capital will be included in the rate base used in calculation of the maximum allowable rate of return; and
- The amortization of contributed capital and the associated offset to depreciation expense financed with contributed capital will be discontinued.

Thus, starting in 1994, the unamortized amount shown in the liability account was added to Acontributions prior to 1980@ and now appears as Acontributions not amortized@ in the equity section of the balance sheet.

Discussion

There are two points of view on how contributed capital should be treated. All agreed that the concept of having customers contribute capital for connection to the system should continue. The divergence of views arises in how to treat this contributed capital. Some argued that capital contributions should be removed from the rate base for rate setting purposes because the customer has taken the risk to provide contributed capital. The customer has, therefore, personally financed this investment and is responsible for paying back interest and principal, assuming a loan was obtained. Assuming that the utility obtained a rate of return on the rate base, which included contributed capital, and that this return covered the financing charges and depreciation, the customer would then be paying twice; once for the contributed capital investment and again through rates.

Another reason advanced for removing contributed capital from the rate base is to achieve consistency with the natural gas companies. It is our understanding that capital contributions made by the customer for connection of natural gas are removed from the rate base for purposes of rate setting.

Others argued that contributed capital should remain in the rate base, at least initially, for the following reasons. The first point, favouring the inclusion of contributed capital, concerns the return on assets. In the past, utilities were not motivated to maximize the return that they could obtain on assets. In fact, most utilities realized a much lower rate of return. The following is an example of actual compared to allowable rate of return as determined by the regulator:

	Actual Rate of Return		Allowed Rate of Return
	Mississauga Hydro	Nepean Hydro	
1996	1.5%	.6%	8.0%
1997	1.0%	(.8%)	8.5%
1998	2.0%	(.6%)	7.5%

Thus, the concept that the customer pays twice if contributed capital remains in the rate base did not apply under the old regulatory framework for the reasons noted above. It was understood however that the utilities= behaviour might change under the PBR framework and that new rules may be required. It was felt, however, that the rules should be applied prospectively to reflect the new environment.

The second point in favour of keeping contributed capital in the rate base is that utilities made public decisions based on the rules of the day. Many utilities, and particularly those who were experiencing growth, decided that growth should finance itself and accordingly levied contributed capital. This was done on the basis that existing customers= rates should not be affected by growth and that new customers were receiving an aesthetic benefit as well as lower rates because contributed capital was used to finance growth. These were public decisions made on the rules of the day and this group argued strongly that any decision to remove contributed capital from the rate base would constitute a reversal of the former regulator=s policy and therefore should not be made retroactively.

The third point involves the market valuation of a utility. The removal of contributed capital from the rate base is tantamount to writing down assets which leads to lower cash flows which, on a present value basis, reduces the market value of a firm. Thus, should a municipality decide to sell a utility with considerable contributed capital on its balance sheet, a much lower selling price would result if it was decided that contributed capital be removed from the rate base. This is a significant problem because, according to Dr. William T. Cannon=s December, 1998, discussion paper on this topic, there was $1.2 billion of assets financed by contributed capital on utility balance sheets as at December 31, 1996.

The final point for keeping contributed capital in the rate base is that its removal would lead to an unfair situation where Company A (with contributed capital) would earn substantially less than Company B (with no contributed capital) even if both companies have the same total assets and the same energy sales.

Options

In the search for a solution it was recognized that the customer should not pay twice, that there should be symmetry between the electricity and gas industries, and that the impact on utilities with contributed capital should be minimized. The following options were considered:

> <u>Option 1:</u>
>
> Electricity distributors will continue to earn a return on contributed capital included in their rate bases prior to an appropriate date, defined as the distribution date of the rates handbook (anticipated in November, 1999). In addition, the practice of charging the depreciation on this contributed capital to operating expenses will continue. The rate of return on this contributed capital component of the rate base will be similar to the rate earned on the non-contributed capital assets.

A return will not be earned on any contributed capital taken after the distribution date and depreciation on this contributed capital will not be charged to operating expenses.

The new Uniform System of Accounts (UsoA) accommodates this option.

Option 2:

Electricity distributors will continue to earn a return on contributed capital included in their rate bases prior to the distribution date. The existing contributed capital will remain in the rate base for the duration of the first generation of the PBR plan (2000-2002). In addition, the practice of charging the depreciation on this contributed capital to operating expenses will continue for the duration of the first generation of the PBR plan only. The rate of return on this contributed capital component of the rate base will be similar to the rate earned on the non-contributed capital assets.

A return will not be earned on any contributed capital taken after the distribution date and depreciation on this contributed capital will not be charged to operating expenses.

In terms of practicality, this option is problematic. According to the CICA handbook, changing the treatment of contributed capital collected in a prior period generally requires restatement of the asset base. Further, when the assets are reduced at the end of the first generation PBR term, those utilities that took contributed capital for growth will see significant decreases in their rate bases. Those utilities will also have substantial decreases in depreciation expenses and corresponding increases in their return on equity (ROE).

Option 3:

Electricity distributors will continue to earn a return on contributed capital included in their rate bases prior to the distribution date. The existing contributed capital will remain in the rate base until the assets are fully depreciated. In addition, the practice of charging the depreciation on this contributed capital to operating expenses will continue. However, the rate of return on this contributed capital component would be a three year weighted average return (total return for all utilities/total assets for all utilities) for the utility composite for the period 1996-1998, rather than the allowed return earned through PBR.

A return will not be earned on any contributed capital taken after the distribution date and depreciation on this contributed capital will not be charged to operating expenses. In terms of practicality, this option is as problematic as Option 2. It would involve the restatement of assets and substantial decreases in rate base and depreciation expenses. In addition, there would be the complexity of not only applying a rate of return to contributed capital taken in a previous period, but applying it at a different rate than that earned on the rate base.

Summary of Positions

While Option 1 was forwarded as a recommendation, Task Force discussions at the subsequent meeting indicated a lack of consensus on this recommendation.

Appendix B and Appendix C contain two views on the issue of taking contributed capital out of a utility's rate base. As well, at the February 18, 1999 meeting Gerry Dupont presented a model of Nepean Hydro's financial position under several contributed capital financing scenarios. The results of this model showed a negative impact on rates in all scenarios when contributed capital was not included in the rate base.

The opposite argument is well stated by Econalysis Consulting Services (Appendix A). In summary the argument states that the assets were not financed by the utility originally and therefore should not be included in the asset base, should not be depreciated and the utility should not receive a return on those assets.

The O&M implications of maintaining the assets is not in dispute. The utility should be allowed to expense all costs associated with maintaining the assets.

All of the discussion thus far has reflected the current operating practices of the utilities and has not investigated alternate operating strategies that would keep rates constant. As well, it was noted that the value of a utility may be affected by the treatment of contributed capital. While the book value will certainly change for most utilities, the market value is independent and may not be affected.

The following text attempts to describe the issues surrounding contributed capital as a regulatory concern. It is important to note that there was consensus on the Task Force that contributed capital should still be considered by LDCs as a form of financing their growth. It is only the treatment of existing Contributed Capital currently included in rate base, from a return basis that is in question.

The focus of resolving this issue should be on the impact to the ratepayers. Customers were under represented on the Rates Task Force and the majority of those discussions dealt with the impact on utilities. It is true that these two items are closely related. However, the work done on rate impacts shows that utilities can still make a considerable return when the contributed capital is removed from their rate base. This will likely not be the last discussion on this issue, even after the Board makes a decision.

It is obvious that the Board is going to have to make this decision. It is too contentious to be resolved at the Task Force level. The full scope of the issue has not been formalized. From the Task Force discussions, it appears that approximately 18% ($1.2B/$6.7B) of the total MEU assets come from contributed capital. The total number of utilities affected by the removal of contributed capital from the rate base is unknown, as well as the percentage of the total customers served. These facts could put this issue in a different light.

The background to this issue has been explained very well by the various Task Force members. The discussion will not be reproduced here except to provide the key elements of the decision. The case to remove contributed capital from the rate base raised the following points:

- The Customer should not pay for their facilities twice;
- The utility should not earn a return on assets provided through contributed capital. This includes depreciation expense as well as inclusion of contributed capital in the asset base; and
- There should be consistency between gas and electricity regulation.

The case to leave contributed capital in the rate base made the following points:

- The previous regulator made a decision that should not be overturned;
- The rate impact will be extreme;
- Utilities will be devalued by this decision; and
- There should be consistency between gas and electricity regulation.

The rate impact work that was completed has shown that the impact on the value of the utility would not be a large issue. It is normal practice for a valuation to be based on a cash flow analysis. The cash flows are not necessarily reduced due to a smaller asset base. Therefore, the potential value of the utility would not be harmed by reducing the rate base.

The pertinent issue is that of rate impact. If all of the contributed capital were removed, the rate impacts would be large. However, market-based returns and transition costs will also potentially cause rate impacts. The removal of contributed capital from a utility's rate base may only be one of several factors that cause rates to increase. Therefore, rate impact on its own is not a sufficient argument.

There was consensus reached on the treatment of contributed capital after deregulation. The decision was to exclude new contributed capital from the rate base after an agreed to date (e.g. Release of the Rate Handbook, Opening of the Market, etc.).

At our meeting of April 30, 1999, it was clear that there were three positions represented by the Task Force: 1. Remove Contributed Capital now, 2. Leave it in, 3. Some kind of compromise. It was decided that there was an unfair representation of the stakeholders at that table and the decision was left unanswered. The discussion did lead to somewhat of a compromise that would "grandfather" the existing contributed capital.

6.2 Background on Contributed Capital Collected by Gas Utilities

Prepared by: Neil McKay – OEB, Manager Facilities.

The utilities have always had a policy that requires customers to contribute towards the cost of expansion. The policy has evolved over time to include a broader range of projects and customer groups.

Initially contributions were required for large industrial customers who needed a dedicated service to supply them with natural gas. The policy required that these industrial customers pay a contribution amount that ensured cost recovery of the pipeline construction. This meant that the NPV of the project was zero over the revenue recovery period (usually 15 years for industrial customers). This approach is still used for projects involving dedicated lines to industrial customers.

Contributed capital for system expansion to new communities has evolved over time. It was only after the utilities had been operating for many years and were “mature” that they started looking at serving areas that were not economically feasible. In some cases the contributions were made through government (e.g. Madoc) on the basis of economic development and industrial growth.

The methodology used by each of the utilities to determine the economic feasibility of a project were different (i.e. different customer attachment periods, different revenue horizons, different tax treatments etc.). Contribution amounts were based on profitability thresholds that were specific to each utility. It should be noted that the contribution policies of the utilities were submitted to and approved by the Board as part of the rate cases.

It was not until the early 1990's that the utilities developed a systematic approach to residential customer contributions. This usually meant pre-determined lump sum payments from customers who wanted to hook up in these communities. In many cases this up-front one-time payment was seen as a financial barrier to customers who could not afford such initial outlays. This allowed for the introduction of the periodic contribution charge (PCC) which presented customers with the option of paying a contribution over time. Essentially, the utilities would “finance” the contribution amounts.

The Board saw the different methodologies and feasibility parameters used by the utilities as problematic. They wanted uniformity and fairness in how the gas distribution system expanded in the Province. The utilities wanted flexibility to expand their systems without having each project scrutinized by the Board for approval. The result was EBO 188 which provides for a common methodology for calculating the economic feasibility of distribution expansion projects and allows the utilities to operate on a portfolio basis.

Under EBO 188 the utilities are expected to maintain a minimum profitability index for their expansion portfolios of 1.10. Within the portfolio, individual project profitability may vary. Should the utilities consider projects that are below 0.8 profitability level however, they are expected to apply a contribution amount to raise it to the 0.8 level.

The Board has not allowed contributed capital to be included in rate base. All contribution amounts are deducted from rate base and are not included in property, plant and equipment calculations.

Appendix A

Interim Process to Develop Unbundled Dx Rates

Delivered kWh (input appropriate classes to apply load profiles)
This should be adjusted to reflect a calander year.

	Billed	Adjustments	Accrued	Revenues - $	Customers
RES NON-EL		0	0		
RES EL		0	0		
Total Residential	131,453,349	0	131,453,349	10,634,495	9,115
SENT LGTS		0	0		
GS <50 kW		0	0		
GS > 50 <1000 kW		0	0		
GS >1000		0	0		
Total GS	281,648,212	0	281,648,212	20,095,977	1,975
LU	48,678,238	0	48,678,238	2,935,684	1
STREET LGTS	2,512,440	0	2,512,440	145,768	
SUB TOTAL	464,292,239	0	464,292,239	33,811,924	11,091
				(excludes late payments, rentals, etc.)	

Wholesale Load and Energy (used to calculate losses)

	KWH Purchased	KWH Generated	Total Wholesale	KWH Adjustment	KWH Sold Adjusted	Loss Factor
ABC Utility	483,270,185	0	483,270,185	0	464,292,239	4.09%

Allocation Data Ontario Hydro Load Research (Note: this is dated information)

Coincident Load Factors

Hours in Month	730	730	730	730	730	730	730	730	730	730	730	730	8,760
RES NON-EL	69.02%	57.80%	70.18%	72.47%	102.14%	59.32%	68.80%	71.38%	63.69%	63.91%	58.77%	60.97%	
RES EL	66.93%	56.12%	67.89%	68.56%	74.90%	66.57%	67.64%	72.18%	85.45%	75.22%	69.30%	62.82%	
Total Residential	68.12%	57.09%	69.26%	71.07%	92.32%	60.76%	68.56%	71.55%	67.54%	66.88%	62.10%	61.67%	
SENT LGTS	62.08%	51.93%	51.60%	43.88%	0.00%	0.00%	0.00%	0.00%	0.00%	61.55%	58.74%	63.53%	
GS <50 kW	92.80%	66.83%	68.89%	66.51%	76.06%	69.11%	56.18%	69.72%	63.38%	65.00%	86.96%	82.67%	
GS > 50 <1000 kW	85.96%	82.22%	95.75%	76.69%	70.96%	48.30%	60.59%	52.14%	71.39%	87.36%	81.01%	75.05%	
GS >1000	83.14%	84.39%	89.04%	80.57%	89.99%	82.85%	83.66%	86.29%	84.86%	89.23%	82.23%	83.63%	
Total GS	86.54%	78.83%	86.46%	75.73%	77.53%	59.90%	65.68%	63.12%	74.08%	83.20%	82.51%	79.53%	
LU	92.21%	81.77%	84.45%	80.93%	89.34%	100.68%	99.26%	88.28%	77.81%	78.54%	74.30%	79.73%	
STREET LGTS	62.16%	51.99%	51.67%	43.94%	0.00%	0.00%	0.00%	0.00%	0.00%	61.63%	58.82%	63.61%	
SUB TOTAL	79.62%	70.33%	79.83%	74.47%	82.87%	63.40%	68.98%	67.92%	73.06%	77.49%	74.42%	72.74%	

Energy Splits

RES NON-EL													
O N ENERGY	4.84%	4.36%	4.65%	3.69%	3.97%	4.63%	4.59%	4.84%	3.73%	3.75%	4.49%	4.32%	51.85%
OFF ENERGY	4.60%	3.75%	3.64%	4.09%	3.41%	3.60%	4.92%	4.32%	3.96%	3.54%	3.53%	4.78%	48.15%
TOTAL	9.44%	8.12%	8.29%	7.78%	7.38%	8.22%	9.51%	9.16%	7.69%	7.29%	8.02%	9.09%	100.00%
RES EL													
O N ENERGY	6.95%	5.87%	5.64%	3.71%	3.20%	2.69%	2.56%	2.62%	2.24%	3.06%	4.61%	5.25%	48.40%
OFF ENERGY	7.49%	6.28%	5.54%	4.93%	3.20%	2.13%	2.70%	2.29%	2.41%	3.34%	4.56%	6.72%	51.60%
TOTAL	14.44%	12.15%	11.18%	8.64%	6.40%	4.81%	5.26%	4.92%	4.65%	6.40%	9.17%	11.98%	100.00%
Total RES													
O N ENERGY	5.52%	4.85%	4.97%	3.70%	3.72%	4.00%	3.94%	4.12%	3.25%	3.52%	4.53%	4.62%	50.74%
OFF ENERGY	5.53%	4.57%	4.25%	4.36%	3.34%	3.12%	4.20%	3.67%	3.46%	3.48%	3.87%	5.40%	49.26%
TOTAL	11.05%	9.42%	9.22%	8.06%	7.07%	7.12%	8.14%	7.79%	6.71%	7.00%	8.39%	10.02%	100.00%
SENT LGTS													
O N ENERGY	3.27%	2.62%	2.46%	1.34%	1.26%	1.04%	0.98%	1.38%	1.73%	2.50%	3.27%	3.11%	24.98%
OFF ENERGY	7.23%	6.16%	6.27%	6.08%	5.48%	5.00%	5.48%	5.88%	6.30%	6.84%	6.67%	7.63%	75.02%
TOTAL	10.50%	8.78%	8.73%	7.42%	6.74%	6.04%	6.46%	7.26%	8.02%	9.35%	9.94%	10.75%	100.00%
GS <50 kW													
O N ENERGY	5.67%	5.14%	5.45%	3.81%	3.93%	4.07%	3.42%	3.64%	3.52%	3.84%	5.04%	5.81%	53.34%
OFF ENERGY	5.59%	4.55%	4.31%	3.67%	3.04%	2.92%	3.02%	2.69%	2.86%	3.23%	3.90%	6.87%	46.66%
TOTAL	11.26%	9.69%	9.75%	7.48%	6.98%	6.98%	6.44%	6.33%	6.39%	7.08%	8.94%	12.68%	100.00%
GS > 50 <1000 kW													
O N ENERGY	5.00%	4.77%	5.04%	4.30%	4.84%	4.86%	4.73%	5.21%	4.61%	4.60%	5.21%	4.21%	57.39%
OFF ENERGY	4.11%	3.71%	3.54%	3.56%	3.03%	2.94%	3.79%	3.47%	3.33%	3.44%	3.60%	4.08%	42.61%
TOTAL	9.11%	8.48%	8.59%	7.86%	7.87%	7.81%	8.52%	8.69%	7.94%	8.04%	8.81%	8.29%	100.00%
GS >1000													
O N ENERGY	3.95%	3.62%	4.17%	3.45%	4.16%	4.12%	3.68%	4.39%	4.08%	4.32%	4.46%	3.80%	48.19%
OFF ENERGY	4.73%	4.08%	4.02%	4.27%	4.11%	3.83%	4.16%	4.29%	4.34%	4.59%	4.13%	5.27%	51.81%
TOTAL	8.68%	7.69%	8.18%	7.73%	8.27%	7.95%	7.84%	8.67%	8.42%	8.91%	8.59%	9.07%	100.00%
GS Total													
O N ENERGY	4.78%	4.46%	4.83%	3.93%	4.44%	4.47%	4.14%	4.64%	4.23%	4.36%	4.93%	4.38%	53.60%
OFF ENERGY	4.60%	3.99%	3.85%	3.82%	3.38%	3.23%	3.76%	3.59%	3.57%	3.78%	3.83%	5.01%	46.40%
TOTAL	9.38%	8.46%	8.68%	7.74%	7.83%	7.69%	7.90%	8.23%	7.80%	8.14%	8.76%	9.39%	100.00%
LU													
O N ENERGY	4.58%	4.43%	5.01%	4.12%	4.60%	4.42%	3.17%	4.57%	4.13%	4.46%	4.58%	3.70%	51.76%
OFF ENERGY	4.31%	4.19%	3.92%	4.38%	4.21%	4.09%	3.60%	4.37%	3.89%	3.96%	3.66%	3.65%	48.24%
TOTAL	8.89%	8.62%	8.93%	8.50%	8.80%	8.51%	6.78%	8.94%	8.02%	8.42%	8.24%	7.35%	100.00%
STREET LGTS													
O N ENERGY	3.27%	2.62%	2.46%	1.34%	1.26%	1.04%	0.98%	1.38%	1.73%	2.50%	3.27%	3.11%	24.98%
OFF ENERGY	7.23%	6.16%	6.27%	6.08%	5.48%	5.00%	5.48%	5.88%	6.30%	6.84%	6.67%	7.63%	75.02%
TOTAL	10.50%	8.78%	8.73%	7.42%	6.74%	6.04%	6.46%	7.26%	8.02%	9.35%	9.94%	10.75%	100.00%
O N ENERGY	4.97%	4.56%	4.88%	3.86%	4.22%	4.30%	3.96%	4.46%	3.91%	4.11%	4.77%	4.38%	52.39%
OFF ENERGY	4.86%	4.20%	3.99%	4.05%	3.47%	3.29%	3.89%	3.71%	3.59%	3.73%	3.84%	5.00%	47.61%
SYSTEM TOTAL	9.83%	8.76%	8.87%	7.91%	7.69%	7.60%	7.85%	8.17%	7.50%	7.84%	8.61%	9.38%	100.00%

Appendix A

Interim Process to Develop Unbundled Dx Rates

Coincident Peak	JAN.	FEB.	MAR.	APR.	MAY	JUN.	JUL.	AUG.	SEP.	OCT.	NOV.	DEC.
RES NON-EL	0	0	0	0	0	0	0	0	0	0	0	0
RES EL	0	0	0	0	0	0	0	0	0	0	0	0
Total Residential	30,409	30,921	24,952	21,255	14,347	21,972	22,257	20,410	18,616	19,628	25,331	30,467
SENT LGTS	0	0	0	0	0	0	0	0	0	0	0	0
GS <50 kW	0	0	0	0	0	0	0	0	0	0	0	0
GS > 50 <1000 kW	0	0	0	0	0	0	0	0	0	0	0	0
GS >1000	0	0	0	0	0	0	0	0	0	0	0	0
Total GS	43,528	43,075	40,317	41,050	40,540	51,584	48,295	52,353	42,284	39,289	42,658	47,418
LU	6,691	7,316	7,341	7,290	6,839	5,866	4,738	7,029	7,157	7,437	7,696	6,402
STREET LGTS	605	605	605	605	0	0	0	0	0	543	605	605
SUB TOTAL	81,234	81,917	73,215	70,200	61,726	79,422	75,289	79,792	68,058	66,897	76,291	84,892

Energy Inclusing Losses													
RES NON-EL													
O N ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0
RES EL													
O N ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0
Total RES													
O N ENERGY	7,552,815	6,634,276	6,796,287	5,059,453	5,093,455	5,474,629	5,385,846	5,642,994	4,448,647	4,821,691	6,194,433	6,320,251	69,424,776
OFF ENERGY	7,569,875	6,252,180	5,820,313	5,968,026	4,574,740	4,270,934	5,753,052	5,017,073	4,730,168	4,760,996	5,288,910	7,395,460	67,401,729
TOTAL	15,122,690	12,886,456	12,616,600	11,027,479	9,668,195	9,745,563	11,138,899	10,660,067	9,178,815	9,582,687	11,483,343	13,715,711	136,826,505
SENT LGTS													
O N ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0
GS <50 kW													
O N ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0
GS > 50 <1000 kW													
O N ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0
GS >1000													
O N ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0
GS Total													
O N ENERGY	14,017,381	13,087,833	14,170,765	11,507,509	13,022,142	13,094,359	12,131,923	13,603,763	12,392,685	12,789,916	14,459,719	12,850,863	157,128,857
OFF ENERGY	13,481,742	11,699,425	11,276,140	11,186,814	9,921,441	9,462,339	11,022,448	10,519,749	10,473,608	11,073,329	11,234,699	14,679,991	136,031,726
TOTAL	27,499,123	24,787,258	25,446,905	22,694,323	22,943,583	22,556,699	23,154,370	24,123,511	22,866,294	23,863,245	25,694,417	27,530,854	293,160,583
LU													
O N ENERGY	2,318,886	2,243,518	2,539,829	2,087,685	2,328,392	2,241,615	1,606,330	2,315,049	2,093,766	2,258,679	2,318,431	1,874,889	26,227,069
OFF ENERGY	2,185,184	2,123,689	1,985,519	2,219,258	2,131,680	2,070,209	1,826,433	2,214,616	1,971,585	2,005,310	1,856,028	1,851,381	24,440,892
TOTAL	4,504,070	4,367,207	4,525,348	4,306,944	4,460,072	4,311,824	3,432,763	4,529,665	4,065,351	4,263,989	4,174,459	3,726,270	50,667,961
STREET LGTS													
O N ENERGY	85,519	68,627	64,392	35,165	32,948	27,270	25,655	36,090	45,114	65,455	85,521	81,450	653,208
OFF ENERGY	189,078	161,072	163,877	158,963	143,440	130,789	143,245	153,836	164,716	179,001	174,333	199,578	1,961,928
TOTAL	274,597	229,699	228,269	194,128	176,388	158,059	168,900	189,926	209,830	244,457	259,854	281,028	2,615,136
O N ENERGY	23,974,601	22,034,255	23,571,273	18,689,812	20,476,937	20,837,873	19,149,753	21,597,895	18,980,213	19,935,741	23,058,104	21,127,453	253,433,910
OFF ENERGY	23,425,879	20,236,366	19,245,849	19,533,062	16,771,301	15,934,271	18,745,178	17,905,274	17,340,077	18,018,637	18,553,970	24,126,410	229,836,275
SYSTEM TOTAL	47,400,480	42,270,621	42,817,122	38,222,874	37,248,238	36,772,145	37,894,932	39,503,169	36,320,290	37,954,378	41,612,074	45,253,862	483,270,185

APPENDIX B - ECONALYSIS CONSULTING SERVICES POSITION ON TREATMENT OF CAPITAL CONTRIBUTIONS

Prepared by: Bruce Bacon, Econalysis Consulting Service

On February 18, 1999 there was a meeting of the PBR Rates Task Force. One of the main discussion items at the afternoon session was the topic of capital contributions and whether it should be included in the rate base or not. There were two strong opinions on this issue around the table. Some members were promoting the opinion that capital contributions should be removed from rate base for rate setting purposes. The rationale for this position is outlined below. However, before the rationale is explained it should be noted that we support the policy of customers contributing capital in order to be connected to the system as long as the treatment of the contribution is just and reasonable.

The primary reason for removing the capital contribution from rate base is to eliminate double counting. The customer has made a capital contribution or investment to be connected to the system. The customer has taken on the risk to provide this investment. The customer has financed this investment on their own out of their own savings or borrowing from a financial institution. If the money is borrowed, the customer is responsible for financial charges as well as paying back the principal. For the sake of this argument, we will assume that generally the return on rate base covers the financial charges and depreciation pays back the principal of the investment. If the customer’s capital contribution is included in rate base then the return on this investment and the depreciation will be included in the revenue requirement for rate setting purposes. This means once these rates were approved, the customer who made the investment would be paying for it twice. Once to the financial institution or out of their own savings and again through the distribution charges they pay. We would submit this is not fair, just or reasonable.

The second reason for removing the capital contribution from rate base is to be consistent with the regulation of natural gas companies in the province. It is our understanding that capital contributions made by the customer for connection of natural gas are removed from gross plant for rate base purpose. Removing the capital contributions from gross plant eliminates the return and the deprecation in revenue requirement attributable to the capital contributions from the customer.

Lastly with the prospect of the MEUs earning commercial rates of return on rate base as well as the responsibility for paying ‘taxes’ there is possibility that distribution charges could increase. Based on a ‘ball park’ estimate we have determine, assuming a 60/40 debt/equity ratio and a return on rate base of 8%, the distribution charges would increase on average by 35% including capital contribution. With the capital contribution excluded from gross plant the increase would be 20%. On the overall average bill, including capital contributions would increase the average bill by about 5% and excluding capital contributions would increase the average bill by around 3% assuming all other items are equal. Obviously, any increase will most likely not be acceptable to customers as the market opens but excluding capital contributions from rate base could be one method to manage the transition and control potential rate increases.

One of the arguments put forth for including the capital contributions in the rate base was it would enhance the value of the MEU if the Municipality decides to sell it. Removing the capital contributions would reduce the value. We would submit there is no real evidence that supports this position and it will only be determined when the market opens.

APPENDIX C - NEPEAN HYDRO ON CONTRIBUTED CAPITAL

Prepared by: Gary Dupont, Nepean HEC

At our last Rates Task Force meeting on February 18, 1999, I had an opportunity to make a presentation on the impact of removing contributed capital from the asset base for purposes of determining a return on assets. You then asked me to submit my arguments in writing for the next Task Force meeting.

There are many factors that will affect the Local Distribution Company's (LDC) rates to the end use customer. The removal of contributed capital from the rate base is probably the factor that will increase current rates (adjusted for cost of power) the most. Furthermore, the market value of an LDC will be drastically reduced if such a policy is adopted, because removing contributed capital from the rate base is tantamount to writing down of assets which leads to lower cash flows which, on a present value basis, reduces the market value of a firm. Thus, should a municipality decide to sell the LDC asset, it would soon discover that assets written down by contributed capital led to a much lower selling price.

This is a very significant problem. According to Dr. William T. Cannon's December 1998 discussion paper on this topic, there was $1.2 billion of assets financed by contributed capital on LDC balance sheets as 31 December 1996. For Nepean Hydro, the net book value of capital assets is $55 million and contributed capital is $30 million. Obviously, the removal of contributed capital from the asset base would seriously reduce the market value of the entity and LDC rates in the future would have to increase by 50.1% on the assumption that the revenue requirement previously funded by contributed capital would now be funded by rates. The shortfall could be funded by debt but, in the long run, the principal plus interest net of taxes

would come out of rates. There are many other LDC's in the province that have the same issue as evidenced by the total $1.2 billion of contributed capital on balance sheets.
The counter argument on this issue centres on the concept that customers should not have to pay twice (i.e. pay the contributed capital and higher LDC rates because the return on asset base would be greater if contributed capital is included in the asset base). Also, there is an argument that assets not financed by the LDC itself should not be entitled to earn a return.

Regarding the first argument that the customer should not pay twice, it must be remembered that the customer initially obtained two benefits. The issue of contributed capital first arose when developers wanted a better sales tool and decided to offer the public the option of having unsightly poles and wires buried. It was logically argued then that the customer receiving this added value should contribute towards the cost. Therefore, such a customer would pay a contributed capital for the difference in the cost between an underground and an overhead system. As well, the existing and new customers would continue to pay the same rates. That was the origin of contributed capital.

The second argument that the asset financed by contributed capital should not be included in the rate base is contrary to normal business principles. Whether an asset is financed through debt, equity, increased selling price or rate, is irrelevant to the value of the asset. If the asset is productive and therefore has to be maintained, depreciated, and replaced, it does not matter how the asset was financed; it should be included in the asset base because removing it, as stated earlier, is the same as writing it off. Recall as well that all of a utility's assets were paid for by its customers who paid regardless of whether the payments were made through contributed capital or rates, and in the past, no one received a return on those assets.

Regardless of the arguments espoused above, whether pro or con, there is one inescapable conclusion. The MEU's of the past made public policy decisions based on the rules of the day. Should the OEB decide not to include contributed capital in the asset base initially, it could be interpreted that the decision made by public boards years back was a wrong decision and that it ought to be rectified now. As previously discussed, the ramifications of such a decision would have serious impact on rates and market value of those utilities who decided to finance with contributed capital.

Should the OEB decide that contributed capital should not be included in the rate base, then I strongly recommend that the OEB make this decision prospectively and not retroactively. In other words, the accumulated contributed capital generated up to 31 December, 1999 should not be removed from the rate base but any contributed capital generated starting 1 January, 2000 be removed from the rate base, LDC's would then be aware of the change in the treatment of contributed capital and would make decisions accordingly. Such a decision would also avoid the very significant downgrade in market value for those MEU's who experienced growth and decided to finance that growth with contributed capital.