RP-2004-0188

ONTARIO ENERGY BOARD

IN THE MATTER OF

THE
2006 ELECTRICITY DISTRIBUTION RATE
HANDBOOK

EVIDENCE OF

ECONALYSIS CONSULTING SERVICES

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ON BEHALF OF

VULNERABLE ENERGY CONSUMERS COALITION

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1 INTRODUCTION

1.1 Background

As of April 1st, 1999, the Ontario Energy Board became responsible for the licensing and regulation of virtually all electricity distribution companies ("LDCs") in Ontario. Initially, these LDCs were issued Transitional Rate Orders that were in effect for a period of up to two years. During this period the OEB developed the Electricity Distribution Rate Handbook ("Rate Handbook") which provided the regulatory framework by which the LDCs were to unbundle their rates prior to market opening and how rates would be adjusted on a going forward basis.

The Transitional Rate Orders issued by the OEB generally maintained the LDC's distribution rates as they existed prior to April 1999, which had been approved by the former regulator (Ontario Hydro). The unbundling process set out in the Rate Handbook involved separating the commodity, transmission and market operations costs included in the LDCs' rates from the distribution-related costs. All LDCs were to file applications for unbundled rates by November 2000 for implementation in 2001. The Rate Handbook also established a Performance Based Regulation ("PBR") framework for adjusting theses rates over the following two years (2002 and 2003). Finally, the Rate Handbook provided for a three-year phase-in of the Market Based Rate of Return ("MBRR") that LDCs were now allowed to earn as a result of the changes initiated under the *Electricity Act, 1998*.

The PBR framework established in the Rate Handbook was considered to be a "first generation PBR plan"[1] that would allow all involved to gain experience with PBR. The Rate Handbook envisioned that there would be a mid-term review of the plan and that the OEB would also conduct a rebasing study to identify the level at which rates should be established for the second PBR term. Finally, the Rate Handbook acknowledged the need for the LDCs to undertake cost allocation studies to better align the rates with costs by customer class for the second generation PBR.

[1] Rate Handbook, page 2-3

However, with the passage of Bill 210 (*Electricity Pricing, Conservation and Supply Act, 2002*) in November 2002, LDC rates were frozen at existing levels and LDCs wishing to make application to the OEB for changes in their rates were required to first obtain the approval of the Minister of Energy. As a result, LDCs in Ontario were not allowed to adjust their rates in 2003 as originally envisioned by the Rate Handbook. At the same time, Bill 210 set the commodity price for electricity payable by low-volume and designated customers at 4.3 cents per kWh. Later in 2003, the government announced that utilities would be allowed to recover some of the costs put on hold by Bill 210 and to also apply for their third MBRR rate adjustment in 2005, provided the funds were used for Conservation and Demand Management (C&DM) initiatives. Effective March 2005, most LDCs in Ontario will have completed the phase-in of their allowed MBRR.

1.2 <u>2006 Electricity Distribution Rate Process</u>

Earlier this year, the OEB initiated a process to prepare a Revised Handbook to assist electricity distributors in the preparation of their applications for 2006 rates. Consistent with the stated intentions of the initial Handbook, a "cost of service" approach is being adopted. To obtain stakeholder input, the OEB established three Working Groups (a Rate Base & Revenue Requirement Working Group; a Rate Design & Cost Allocation Working Group and Comparators & Cohorts Working Group) and invited interested parties to participate. The purpose of the Working Groups (and the sub-groups subsequently established) was to identify the issues that should be addressed in the Revised Handbook and then develop drafts of the required sections – highlighting any areas where there was disagreement or lack of consensus. On November 1 &2, 2004, an Issues Day was held before the Board at which time the progress of the Work Groups was reported and the Board Panel was asked to rule on:

- Various issues of scope in terms of the issues that should be dealt with by the Revised Handbook, and
- Proposals with respect to the filing evidence for issues that were still unresolved.

The OEB's schedule called for a draft of the Revised Handbook (identifying alternatives in those areas where full consensus has not been achieved) to be issued the week of December 6th, 2004 and evidence to be filed on December 13th, 2004[2]. An oral hearing is scheduled to commence on January 17, 2005 to deal with the matters addressed in evidence. The argument to follow will allow parties to make comment on any portion of the proposed Revised Handbook and the issues dealt with during the oral hearing process.

2 PURPOSE OF EVIDENCE

One of the issues discussed by the Rate Design and Cost Allocation Work Group was the question of Rate Impacts and Rate Mitigation. The original Rate Handbook included a requirement that the move to rates incorporating a full MBRR be phased in over 3-years[3] in order to mitigate the rate impacts on customers. In addition the original Rate Handbook also called for a two part distribution rate structure which included the introduction of a monthly customer charge for many LDCs.

The adoption of such a rate design change (i.e., a monthly customers charge as opposed to purely volumetric charges) resulted in the potential for a significant bill impact on small volume customers. As a result, the original Rate Handbook also required that the monthly service charge be set such that the bill impact resulting from the change did not exceed 10% of a low volume customer's total bill. This was to be achieved by lowering the monthly service charge and increasing the volumetric charge to a point where the impact on the target customers was less than 10%. The process for varying the proportionate shares of the fixed/variable rates required the class to remain revenue neutral. In addition, the original Rate Handbook limited the impacts due rate harmonization to a further 5% of the total bill. Given the rate impact constraints previously mandated in the first generation Rate Handbook, the question therefore arose as to what requirements the 2006 Rate Handbook should include with respect to rate impacts and rate mitigation.

[2] RP-2004-0188, Procedural Order No. 2
[3] RP-2000-0069, Decision With Reasons, Paragraph 3.1.19

Issues discussed during the Working Group deliberations included[4]:

- The appropriate basis for comparison (i.e., total bill vs. distribution portion);
- The percent limit that should be adopted and whether a dollar threshold should also be considered;
- The treatment of bill harmonization impacts; and
- The options open to utilities and treatment of the applications for those utilities with rate/bill impacts that exceed the established limits.

On Issues Day, this topic was identified[5] as being "unresolved". Furthermore, representatives for VECC (Vulnerable Energy Consumers Coalition) argued[6] that evidence was required in this area in order to assist stakeholders and the Board itself in determining how rate impacts are best calculated; what the threshold levels for should be for bill/rate increase; and what the requirements should be for those distributors who exceed the guidelines. In its Issues Day rulings the Board concluded that:

> The Panel is prepared to hear evidence on this issue. The Board regards rate mitigation and implementation of fundamental importance in the overall consideration of 2006 rates. The Board finds that VECC, as a representative of vulnerable energy consumers, is in a good position to prepare evidence and proposals on this issue. The Board recognizes, as was stated on the record, that other parties may wish to call reply evidence in response to the evidence filed by VECC.

As a result, following Issues Day, VECC retained Mr. William Harper and Ms. Joyce of Econalysis Consulting Services (ECS) to prepare evidence that would assist both stakeholders and the OEB in establishing the requirements that should be included in the Revised Handbook with respect to Rate Impacts and Rate Impact Mitigation. Mr. Harper has over 25 years experience in the electricity industry gained through positions held with the Ontario Ministry of Energy and Ontario Hydro (and one of its successor companies Hydro One Networks). While at Ontario Hydro, his responsibilities included Ontario Hydro's wholesale rates and Ontario Hydro's regulation of the province's municipal electric utilities; as well as the coordination of the Company's overall participation in public review processes. During this period he testified

[4] Issues Day Transcript Volume 2, paragraphs 505-518
[5] Issues Day Transcript Volume 2, paragraphs 505-518
[6] Issues Day Transcript Volume 2, paragraphs 827-837

frequently before the OEB on rate and regulatory matters. Since joining ECS, he has provided support to intervenors in energy proceedings in British Columbia, Manitoba, Ontario and Quebec on rates, revenue requirements, industry restructuring and resource planning. He has testified as an expert witness before the Manitoba Public Utilities Board, the Quebec Régie de l'énergie and the Manitoba Clean Environment Commission.

Ms. Poon's 16 year career in the natural gas industry includes experience with TransCanada Pipelines, Centra Gas Ontario and Enbridge Consumers Gas. Her responsibilities have included economics and demand forecasting as well as rate design. She has experience in natural gas upstream pipelines, marketing and distribution. Her regulatory experience has included the preparation of natural gas and electricity submissions on behalf of intervenors and LDC applicants requiring the review of financial forecasts and revenue requirement projections in over 20 cases in proceedings in British Columbia, Manitoba and Ontario. She has testified before the OEB with respect to rate design and cost allocation matters as an employee of Enbridge Consumers Gas and as a consultant in the Union Gas RP-2002-0130 proceeding. She has also been involved in proceedings concerning the rates for both the Manitoba Public Insurance Corporation and the Insurance Corporation of British Columbia.

Full CV's for both consultants are provided in Appendix B. The consultants have been retained as independent experts sponsored by VECC and the views expressed in this Report are those of the consultants.

The report is structured as follows:

- Section 1 – is the Introduction.
- Section 2 – addresses the Purpose of the Report.
- Section 3 – provides General Context by looking at the role of "rate impacts" under traditional "cost of service" regulation in general; in an unbundled bill environment such as Ontario's.
- Section 4 - provides more specifics by looking at how issues related to the electricity rate/bill impacts have been dealt with in the past both in Ontario and in other Canadian

jurisdictions and what's been considered reasonable versus unreasonable by regulators and other government decision makers.

- Section 5 – discusses the customers' perspective with respect to rate impacts.
- Section 6 – looks specifically at the 2006 EDR process and rate impact considerations as they relate to each of the main steps in "cost of service" regulation and presents a series of recommendations regarding:
    1. The rate impact calculations that LDCs should be required to file as part of their 2006 Distribution Rate Application.
    2. The rate/bill impact thresholds that should be incorporated into the Revised Handbook and the basis on which they should be determined.
    3. The Guidelines that should be incorporated in the Revised Handbook as to the requirements for those LDCs exceeding the thresholds.

3 CONTEXT FOR RATE IMPACT CONSIDERATION

3.1 Principles of Cost of Service Regulation

Under cost of service regulation, the company (utility) concerned is required to file a rate application with the necessary documentation supporting any requested change to current rate levels or rate design. The regulator then establishes a proceeding to allow input from interested parties following which a decision is rendered from which the establishment of the final rates and Rate Order can be derived. In making its decision the regulator is required to balance the interests of the utility's shareholders and customers.

In terms of overall rate levels, one of the key principles underlying cost of service regulation is "fair return" in that regulated utilities are to be allowed to recover the costs for regulated operations and earn a fair rate of return on the prudently incurred investments associated with those regulated operations. The amount of revenue required by a utility to cover the sum of these two is referred to as the "revenue requirement". However, at the same time, regulators are expected to take into account consumer interests with respect to rate stability and predictability.

In addition, regulators are frequently guided by additional principles such as encouraging efficiency in both utility operations and the end-use of electricity.

To strike a balance between shareholder and consumer interests, regulators seek to ensure that the costs included in the utility's revenue requirement are "just and reasonable". To this end, the utility is expected to demonstrate in its rate application that the costs requested are been "prudently incurred" and that the investments for which they are seeking cost recovery are for assets that are "used and useful" in providing the regulated services. In fact, under cost of service regulation, the burden of proof with respect to an Application rests with the utility as the applicant. Furthermore, it generally fair to say that the greater the change (increase) requested in the overall level of customer rates the greater the tension between shareholder and ratepayer interests and the more closely a utility's costs are scrutinized in order to ensure that they are just and reasonable.

This need to strike a balance between the rates paid by consumers and the rate of return that shareholders are allowed to earn is one of the challenges faced by the Ontario Energy Board. This is clearly evidenced by its objectives, as set out in *the Ontario Energy Board Act, 1998*[7], which include:

a) To protect the interests of consumers with respect to prices and reliability and quality of electricity service, as well as
b) To facilitate the maintenance of a financially viable electricity industry.

Cost of service regulation also involves allocating the revenue requirement to customer classes and then designing rates so as to recover the approved revenue requirement. One of the key principles in these last two steps is "fairness" in the apportionment of costs. Fairness is generally interpreted as allocating costs to those who cause them (i.e., those who utilize or benefit from the associated services) such that customers in similar situations are treated equally. While neither of these steps impacts on the overall level of revenue requirement both can impact on the rates applicable to individual customers and led to variations in rate/bill impacts across a utility's customer base.

[7] Section 1

As well as fairness and recovering the overall revenue requirement, generally accepted objectives[8] for cost allocation and rate design also include:

- Encouraging efficiency in the end use of electricity, and
- Ensuring rates are simple, understandable and publicly acceptable.

Public acceptability, or lack thereof, for proposed changes in rates is frequently tied to rate/bill impact that customers will receive as result of the changes. This is particularly the case if the changes are significant and lead to unacceptable increases or what is commonly referred to as "rate shock". Again, regulators find it necessary to strike a balance between adjusting rates so that they continue to be "fair", while protecting customers' interests with respect to rate stability and predictability and meeting whatever other objectives have been set for/deemed appropriate by the regulator. In the case of rate adjustments required as a result of cost allocation or rate design, regulators typically balance these two interests by phasing in any required changes in over a period of time so as to ameliorate the year over year rate impacts. In such instances the issue is not as much balancing the interests of customers versus shareholders but rather balancing the interests of various customer groups.

3.2 Rate Impacts and Restructured Electricity Market

In restructured electricity markets such as Ontario's, consumers bills for electricity are comprised of both regulated and unregulated charges and even the regulated charges can originate from a number of different sources. Table 1 sets out the various component of consumer's bill (for different classes of consumers) and, for each, indicates whether the charges are regulated or market-based and, if regulated, who the service provider is and the basis for the regulation.

[8] James C. Bonbright, Albert L. Danielsen and David R. Kamershen, Principles of Public Utility Rates, Second Edition, Public Utilities Reports, Inc. 1988, page 383

Table 1

Components of an Ontario Electricity Consumer's Bill

Customer Group / Charges	Low Volume and Designated Customers	Large Volume and Non-Designated Customers	Registered Market Participants
Electricity (Commodity & Uplifts)	• Regulated • Set by Govern. Regulation	• Unregulated • Market Based	• Unregulated • Market Based
Transmission	• Predominate provider is Hydro One Networks • Regulated by the OEB	• Predominate provider is Hydro One Networks • Regulated by the OEB	• Predominate provider is Hydro One Networks • Regulated by the OEB
Distribution	• Provided by Local LDC • Regulated by the OEB	• Provided by Local LDC • Regulated by the OEB	• Provided by Local LDC • Regulated by the OEB
Wholesale Market Service	• Provided by IEMO • Regulated by the OEB	• Provided by IEMO • Regulated by the OEB	• Provided by IEMO • Regulated by the OEB
Debt Retirement Charges	• Regulated • Set by Government Regulation	• Regulated • Set by Government Regulation	• Regulated • Set by Government Regulation

Standard Service Supply (if applicable)	• Provided by LDC • Regulated by the OEB	N/A	N/A

As the table illustrates, the OEB is only responsible for regulating a portion of the charges that make up a consumer's total bill for electricity. This has several implications when considering rate impacts:

- First – The overall rate/bill impacts of any approved rate increases for transmission, wholesale market service charges or distribution will be less when considered in terms of the consumer's overall bill. On average distribution costs form 23% of a typical[9] residential customer's total monthly charges. As a result, a 10% increase in these charges would produce a 2.3 % increase in the typical residential customer's bill. However, the portion distribution costs in a typical residential customer's bill will vary across the individual LDCs from 9%-37%.
- Second, since the regulated charges under the OEB's jurisdiction may not necessarily all come up for review simultaneously and other components of the bill are not within the purview of the OEB, the total bill impacts customers will eventually see over fixed period of time are difficult to determine.
- The level of detail included in the standard bill format will affect customers' ability to understand the reasons for overall changes in their total bill. While limited disclosure or aggregation of individual bill components will mask the impacts of changes in individual charges; it could frustrate consumers' understanding of their bills.
- Finally, changes in unregulated charges are, by definition, uncontrollable. However, they will impact on a customer's total bill and influence perceptions with respect to the reasonableness of changes in regulated charges.

[9] Defined as a customer using 1,000 kWh per month.

4 RATE IMPACT – REGULATORY PRACTICE AND GOVERNMENT POLICY

4.1 Ontario

4.1.1 Experience with Natural Gas

History of Bill Changes

Since 1999, both Union Gas and Enbridge have received a number of "approvals" from the Ontario Energy Board for adjustments to both the distribution and commodity rates charged to residential customers. The commodity price changes are predominately adjusted through the quarterly QRAM process, which is formulaic in nature as it establishes the commodity price and recovers gas cost deferral balances. Tables 2 and 3 set out the annualized charges for typical residential customer based on the rates in effect as of each rate change and the resulting bill impact for each.

In the case of Enbridge, the total bill for a residential customer has increased by over 50% since 1999; however the distribution portion[10] of the bill has increased by less than 20% (roughly 3.6% per annum). For Union Gas the total bill for a residential customer has also increased by over 50% in the same period. However, in the latter case the PBR Decision of RP-1999-0017 and the changes in cost allocation have led to virtually no change in residential distribution costs.

The historical natural gas bills provided in the tables indicate the most substantive rate impacts to customer bills are due to changes in the natural gas commodity charge. Given that natural gas commodity is a price determined by the supply and demand factors in the total North American market where the utility is a price taker and has no control of the natural gas commodity price, customers are more accepting of these large price variances and understand that their alternative is to seek a fixed commodity supply contract with a licensed gas marketer. However, over 50%

[10] It should be noted that portion of utility's distribution costs is affected by changes in natural gas commodity costs.

of customers have accepted the volatility of gas commodity prices and associated quarterly rate adjustments.

Table #2
Enbridge Residential Rate History

Date of Change	Distribution Charge	Percent Change	Commodity Charge	Total Bill	Percent Change
Oct-99	$567.02	n/a	$437.59	$1,004.61	n/a
Feb-00	$583.97	2.99%	$437.61	$1,021.58	1.69%
Jun-00	$597.50	2.32%	$545.21	$1,142.71	11.86%
Oct-00	$601.98	0.75%	$744.54	$1,346.52	17.84%
Jan-01	$605.61	0.60%	$876.14	$1,481.75	10.04%
Mar-01	$634.63	4.79%	$1,153.85	$1,788.48	20.70%
Jul-01	$627.83	-1.07%	$1,153.85	$1,781.68	-0.38%
Sep-01	$614.16	-2.18%	$730.21	$1,344.37	-24.54%
Jan-02	$602.69	-1.87%	$650.85	$1,253.54	-6.76%
Apr-02	$590.99	-1.94%	$573.12	$1,164.11	-7.13%
Jul-02	$612.50	3.64%	$749.90	$1,362.40	17.03%
Aug-02	$613.37	0.14%	$748.64	$1,362.01	-0.03%
Oct-02	$625.15	1.92%	$685.13	$1,310.28	-3.80%
Jan-03	$627.29	0.34%	$762.60	$1,389.89	6.08%
Apr-03	$637.83	1.68%	$954.28	$1,592.11	14.55%
May-03	$657.05	3.01%	$956.07	$1,613.12	1.32%
Oct-03	$662.02	0.76%	$843.16	$1,505.18	-6.69%
Jan-04	$668.10	0.92%	$761.01	$1,429.11	-5.05%
Apr-04	$675.58	1.12%	$863.66	$1,539.24	7.71%
Total		19.15%			53.22%

Table #3
Union Gas Residential Rate History

Date of Change	Distribution Charge	Percent Change	Commodity Charge	Total Bill	Percent Change
Dec-99	$521.04	n/a	$488.71	$1,009.75	n/a
Apr-00	$521.04	0.00%	$476.95	$997.99	-1.16%
Jun-00	$521.04	0.00%	$529.86	$1,050.90	5.30%
Oct-00	$521.04	0.00%	$710.63	$1,231.67	17.20%
Jan-01	$521.04	0.00%	$798.81	$1,319.85	7.16%
Mar-01	$521.04	0.00%	$1,123.60	$1,644.64	24.61%
Nov-01	$555.27	6.57%	$681.99	$1,237.26	-24.77%
Jan-02	$555.27	0.00%	$885.99	$1,441.26	16.49%
Apr-02	$555.27	0.00%	$581.30	$1,136.57	-21.14%
Jul-02	$555.27	0.00%	$703.28	$1,258.55	10.73%
Jan-03	$561.94	1.20%	$729.73	$1,291.67	2.63%
Mar-03	$571.49	1.70%	$833.78	$1,405.27	8.79%
Apr-03	$542.80	-5.02%	$833.78	$1,376.58	-2.04%
May-03	$664.25	22.37%	$957.55	$1,621.80	17.81%
Jul-03	$655.64	-1.30%	$988.98	$1,644.62	1.41%
Oct-03	$738.54	12.64%	$915.51	$1,654.05	0.57%
Jan-04	$523.17	-29.16%	$802.66	$1,325.83	-19.84%
Apr-04	$513.64	-1.82%	$950.71	$1,464.35	10.45%
Jul-04	$512.68	-0.19%	$1,068.66	$1,581.34	7.99%
Oct-04	$514.78	0.41%	$1,054.88	$1,569.66	-0.74%
Total		-1.20%			55.45%

The large May-03 distribution rate increase in Union Gas of 22.37% was an impact predominately driven by the recovery of gas supply related costs that are embedded in the distribution rate charge, for items such as UFG, and load balancing.

Cost Allocation Issues

Despite the relative stability in the gas distribution increases in the previous years, rate shock and rate mitigation have been relevant and active issues for both Union Gas and Enbridge in recent proceedings. Large distribution rate impacts have been an issue due to various cost allocation changes in both utilities. In the Union case the issue of the elimination of the Delivery Commitment Credit "DCC" mounted significant attention given the large distribution rate impacts that would a rise to large volume customers. The elimination of this DCC, would impact the large volume customer's distribution rates from 8.6% to 49%. These impacts were viewed to be material. As a result, the Board ordered Union in the RP-2001-0029 proceeding to provide a phasing out of the credit program over time in a subsequent proceeding.

In the following RP-2002-0130 proceeding, Union did not provide a phase out proposal but rather argued to maintain the embedded credit. The Board, in the same proceeding, in effect proposed and ordered that a phase out period of 5 years be used to eliminate the DCC, which in effect limited the largest customer distribution rate impact to roughly 9.8% associated with this cost allocation change.

Enbridge Gas faced a similar issue on rate shock to customer classes associated with the cost allocation change to its upstream transportation and storage costs in the RP-2003-0203 proceeding. The impact of the full cost allocation change would cause distribution rate increases to large volume customers that the range from 4% to 48%. Through an the ADR process, all parties agreed to phase in this cost allocation change such that the greatest rate impact to a rate class negatively impacted would be 9% for the first 3 years, and elimination of the remaining changes in the fourth year.

4.1.2 2000 Electricity Distribution Rate Handbook

Minister's Directive

In March 2000, the Board issued the first version of the Electricity Distribution Rate Handbook which described the procedures that LDCs were to follow in order to unbundle their rates for market opening and establish a distribution revenue requirement that would incorporate a market based rate of return and payments in lieu of taxes (PILS). Subsequently, a number of large utilities filed rate applications for increases in revenue requirement (including cost of power) ranging from 5.3% to 12.1% and averaging 8.5%[11]. Given that the cost of power assumptions underlying the quoted increases remained unchanged, the applications represented significantly higher increases in distribution-related revenues and rates.

[11]OEB Decision with Reasons, RP-2000-0069, Paragraph 1.0.4

This effect is demonstrated in Table 4 which sets out, for a cross-section of LDCs[12], the total revenue requirement change (including cost of power) and the distribution revenue requirement change associated with the LDCs moving to full MBRR (with and without the inclusion of PILs). As can be seen from the table, the average impact on the distribution revenue requirement was 36% for simply including the MBRR and increased to 57% when PILs were also included.

TABLE 4

Revenue Requirement Change to Obtain Full MARR

	% Change to Distribution Revenue (excludes COP)	% Change to Total Revenue Requirement (includes COP)
Average	36%	5%
Maximum	88%	9%

Revenue Requirement Change to Obtain Full MARR + Full PILs

Average	57%	8%
Maximum	127%	15%

Note: Values derived from LDCs RUD models as filed with the OEB

On June 7, 2000 the Ontario Minister of Energy, Science and Technology issued a policy directive to the OEB requiring that "the Board shall give primacy to the objective "to protect the interests of consumers with respect to prices and reliability and quality of service". Following a generic proceeding to address the implications of the directive on the Rate Handbook, the Board adopted[13] a three-year phase in process for LDCs to achieve full MBRR. Furthermore, the Board determined that LDCs would not be entitled to recover (in future rates) the deferred return.

[12] See Appendix A for a description as to how the cross-section was developed
[13] RP-2000-0069 Decision With Reasons, paragraph 3.1.19

Table 5 sets out the impact on the same cross-section of LDCs of the Board's decision which significantly reduced the impact to customers, as the average change to the total revenue requirement was reduced to 2% and the average distribution revenue increase to the utility was now 12%.

TABLE 5

Revenue Requirement Change to Obtain 1/3 MARR

	% Change to Distribution Revenue (excludes COP)	% Change to Total Revenue Requirement (includes COP)
Average	12%	2%
Maximum	29%	3%

Note: Values derived from LDCs RUD models as filed with the OEB

Final 2000 Electricity Distribution Rate Handbook

As well as establishing a three year phase-in period for LDCs to achieve their full MBRR, the final 2000 Electricity Distribution Rate Handbook set out a PBR framework for adjusting rates for the two years[14] following the initial unbundling and setting of rates. The scheme defined an input price index (IPI) for LDCs and called for the OEB to annually collect data such that it could publish the year over year percent change in the IPI. Utilities would then be allowed to adjust their rates, in March of 2002 and 2003, by the percentage change observed in the IPI less a productivity factor of 1.5%. However, as a result of passage of Bill 210 in December 2002 the rate adjustment mechanism was only applied for one year – March 1, 2002. The IPI, as calculated by the OEB, increased by 0.4% in 2001. After the allowance for the 1.5% productivity factor the result was a "downward adjustment" in LDC rates (excluding other factors such as revised PILS calculations and the continued phase-in of the MBRR).

[14] Then anticipated to be 2002 and 2003

Hydro One Networks' January 2001 Distribution Rate Application

Hydro One Networks', in its 2001 Distribution Rate Application indicated that strict application of the Rate Handbook in conjunction with a wholesale cost of power change would result in an increase of 13% in retail customers bills[15]. The Company further indicated that in discussions regarding its plans for distribution rates, the Ontario Government expressed concerns that the phase-in principles permitted under the Rate Handbook, when combined with increases in the cost-of-power, would cause unduly negative customer impacts.

To address this, Hydro One Networks' application proposed to limit the increases in the average retail customer's total bundled bill to 4% on October 1, 2001. The Company also proposed an increase of 2.8% in the total bundled bill on March 1, 2002 and (in the event the market did not open) a further 2.8% increase in total bundled bill on March 1, 2003. Hydro One Networks plans[16] for accommodating these lower rate increases included:

- reductions in ongoing costs,
- delaying of expenditures that would not compromise safety and reliability,
- the deferral of the recovery of cost incurred respecting PCB management and the remediation of contaminated lands, and
- lower net income expectations.

4.1.3 Ontario Regulation 42/04

Following market opening in May 2002, the monthly commodity rates for smaller volume customers were established so as to "flow through" to consumers the LDC's cost of purchasing electricity from the IMO. For low volume and designated customers, this practice was changed in November 2002 and the commodity price was fixed at 4.3 cents/kWh. The commodity price for electricity then remained unchanged until April 2004 when the commodity pricing structure for these customers was changed to 4.7 cents / kWh month for the first 750 kWh used in a month

[15] Exhibit D, Tab 1, Schedule 1, page 4 (Revised 2001-09-06)
[16] Exhibit D, Tab 2, Schedule 1 (Amended 2001-01-19)

and 5.5 cents / kWh for any additional electricity consumed during the month. The average total bill impact, over all LDCs in the province was roughly 7% - assuming 1,000 kWh use per month with individual impacts ranging from 6% to 7.8%. Table 6 provides a more detailed analysis of the impact of this commodity cost change for the cross-section of LDCs.

TABLE 6

Rate Impacts to Individual Residential Customers due to change in cost of power

Monthly kWh	Average % change	Maximum % change	Minimum % change
250	3.2%	4.2%	2.3%
500	4.0%	4.8%	3.3%
750	4.3%	5.1%	3.8%
1,000	6.8%	7.8%	6.1%
1,500	9.5%	10.7%	8.7%
2,000	10.9%	12.2%	10.0%

Note: LDCs 2004 rates obtained from OEB decisions
Residential Volumes based on RUD levels

4.2 British Columbia

4.2.1 BCUC 1992 Rate Design Decision re: BC Hydro[17]

In 1991, BC Hydro filed a Rate Design Application with the British Columbia Utilities Commission (BCUC) which proposed to eliminate the then existing declining block rate structure for its residential and general rate categories. The required adjustment would be done in conjunction with general rate increases. During the subsequent proceeding, parties offered two definitions of rate shock. The first was increases greater than 10% per annum; whereas the second involved a two-times rule which stipulated that if as a result of rate design bills were to increase by more than double the increase received on the average bills in a customer class, this

[17] Issued April 24, 1992

would begin to encroach on the realm of rate shock – that is unacceptably high rate increases. The BCUC in its determinations concluded that whether a particular increase constitutes rate shock depends on the overall rate environment and the circumstances of the particular customer. The BCUC concluded that it was its responsibility to assess these circumstances and determine when rate shock may be properly said to have occurred, but accepted for the purposes of the Application the "two-times" rule. (Note: At the time there were prospects of a potential 7% revenue requirement increase and no imperative changes to cost allocation).

4.2.2 BCUC 2004 Decision re: BC Hydro's 2004/05 and 2005/06 Revenue Requirement[18]

In December 2003, BC Hydro applied to the BCUC for an order to increase domestic rates by 7.23 % effective April 1, 2004 and by a further 2 % effective April 1, 2005. In January 2004, the BCUC approved the application for 7.23% as of April 1, 2004 on an interim basis – subject to refund with interest. However, in April 2004, BC Hydro filed an evidentiary update and revised its application to obtain a 1.67% increase (over and above the 7.23%) to be effective 30 days after the Commission's decision on the Application was issued. The applied-for additional increase of 2% to be effective April 1, 2005 was withdrawn. The overall effect of the revised Application was a total increase of 8.9%. It should be noted that the rate increase was to be applied equally across all customer classes.

The BCUC in rendering its October 2004 Decision viewed the applied for increase as a significant one-time increase, noting that rates had declined in real terms by 14% since 1993 and that costs had increased over the same period. The Panel concluded that BC Hydro had established that a one-time significant increase in revenue requirement was needed in order to earn its allowed rate of return but expressed the expectation that BC Hydro would manage future rate increases within the context of inflation. Through out its decision the BCUC made a number of findings regarding specific aspect of BC Hydro's rate application such that when BC Hydro submitted its compliance filing after the Decision, the final rate increase required was only 4.85% effective April 1, 2004[19].

[18] Issued October 29, 2004
[19] BCH's November 15th, 2004 Compliance Filing

4.3 Saskatchewan

4.3.1 2001 Rate Review Panel[20]

In 2001 SaskPower proposed a set of rate changes that were designed to generate an overall 5.4% increase. However, the proposal also included a rebalancing of the cost allocation between customer classes and rate design adjustments. The overall effect of the cost allocation changes was a range of customer class rate increases from 0.9% to 12%. In order to address rate impact concerns SaskPower proposed to limit the impact due to rate redesign such that no customer would see a rate/bill impact greater than 10% above the relevant class average (i.e., the maximum increase would be 22%). The Rate Review Panel in its Report to the Minister concluded that “a 22% rate increase for electrical service could be considered to create rate shock” and recommended that the “maximum increase for an individual customer be capped at 13 percent”[21].

4.4 Manitoba

4.4.1 Manitoba Public Utility Board Orders 101/04 and 143/04[22]

In January 2004, Manitoba Hydro applied to the Manitoba Public Utilities Board (MPUB) for approval of rate schedules incorporating average rate increases of 3% effective April 1, 2004 and a further 2.5% effective April 1, 2005. However, assuming an August 1, 2004 implementation date the first requested increase would give rise to an average increase in customers’ bills of 4.3%. This was Manitoba Hydro’s first application for a rate increase since 1997 and was triggered by a substantial drought that led to losses in excess of $400 million for its 2003/04 fiscal year. At the same time, Manitoba Hydro sought to make adjustments in the relative costs allocated to customer classes and to initiate a rate design restructuring. For residential customers

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[20] Saskatchewan Rate Review Panel Report to the Minister on The Proposal from SaskPower for Changes in Electrical Rates, December 6, 2001
[21] Rate Review Panel Report, page 15
[22] Issued July 28, 2004 and November 18, 2004 respectively

(who were one of the classes more significantly impacted) the result was an average class increase of 5.5% (versus 4.3%) and individual customer bill impacts of up to 6.7%.

During the proceeding Manitoba Hydro set out its general rate making objectives, which included the following impact considerations:

- Annual adjustments in revenues by customer class should be less than 2 percentage points greater than the overall general rate increase.
- For residential customers, no customer will experience a bill increase which exceeds the greater of $3.00 per month or three percentage points more than the class average increase.
- For general service customers, no customer will experience an increase in average monthly bill over a year which exceeds the greater of $5.00 per month or five percentage points more than the class average increase.

In its Decisions the MPUB expressed concern with respect to Manitoba Hydro's current financial circumstances and directed that Manitoba Hydro increase its rates for all customer classes by 5% effective August 1, 2004. The MPUB also granted a conditional increase of 2.25% for all customer classes effective April 1, 2005 and a further conditional increase of 2.25% for all customer classes effective October 1, 2005. While increases apply equally to all customer classes, the MPUB did approve the rate design changes proposed by Manitoba Hydro. The PUB noted that in coming to its decision it had considered the issue of rate shock and opined that rate increases for most customers will be within the thresholds put forward by intervenors, i.e., no more than 8-9% for any customer for the August 2004 increase.

4.5 <u>North-West Territories</u>

For the past 10 years the Northwest Territories Power Corporation has been working to rationalize the rates for an inherited rate system that involved 50 separate rate zones and to implement rates that are more cost-reflective at both the community and customer class level. In order to ameliorate the associated rate impacts, the Public Utilities Board of the Northwest

Territories has adopted[23] a 15% cap on the maximum annual increase allowable as a result of adjustments to arising from moving customer class rates towards the accepted revenue to cost ratio band of 95% to 105%. Furthermore, with respect to the 2003 Decision, it should be noted that for residential and general service customers the 15% cap applied to the energy charges only (customer charges and demand charges were held constant).

4.6 New Brunswick

The New Brunswick Board of Commissioners of Public Utilities legislative authority[24] with respect to reviewing rate changes proposed by New Brunswick Power-Distribution only applies in cases where the utility is proposing rate increases to one or more rate classes greater than 3%. On this basis, there has not been a distribution rate hearing in over 10 years.

4.7 Nova Scotia Utility and Review Board

In December 2001, Nova Scotia Power applied to the Board for an average increase in rates of 8.9%, with individual customer classes potentially experiencing rate increases in excess of 16%. During the coursed of the proceeding before Review Board, two different perspectives were offered with respect to the definition of “rate shock”. The first defined rate shock in the context of inflation and suggested that with inflation at 2-3% per annum then anything above 10% would be “rate shock”. However, if inflation was at 7-8% then rate shock might be 15-20%. The second definition linked rate shock to the underlying rate increase and suggested that customer class increases of 150% of the average rate increase would be indicators of rate shock as would individual increases over 200% of the average rate increase. In its findings, the Board agreed[25] with the later definition and the notion that rate shock must take into account the underlying average level of increase. In its Decision, the Board also reduced the requested level of revenue requirement such that the actual rate increase was only 3.3%.

[23] Decision 3-2003, pages 27 and 31
[24] Prior to amendments introduced earlier this year, the “cut-off” point established in the legislation was a 3% overall average increase for distribution customers.
[25] Decision NSUARB-NSPI-P-875, page 123

4.8 Newfoundland & Labrador Board of Commissioners of Public Utilities

In May 2001, Newfoundland & Labrador Hydro (NLH) filed a general rate application. As part of the application, NLH sought to simplify its rate classes and rate structures and standardize the application of rates across its system. In order to address the potential impacts, NLH proposed that:

- No rate class (based on the standard rate categories) should receive an increase of more than 20%;
- No Domestic or small General Service customer should receive an increase of more than $20 per month; and
- Large General Service customers should receive increases of no more than 20% unless circumstances are unique.

In its Decision[26], the Board expressed the view that the resulting rate increases from applying these guidelines would not cause “rate shock”. It encouraged NLH to adhere to the guidelines as it redesigned its rates but noted that if their application prevented the design of rates that recovered costs, then the Board would support some adjustment to the parameters, if required.

4.9 Conclusions

As can be seen from the foregoing the approach to addressing rate impacts and the criteria as to what are considered acceptable rate impacts varies by jurisdiction and by the particular circumstances involved. However, overall it is possible to draw some broad conclusions:

- Regulators do make distinctions among average rate increases based on the total revenue requirement; customer class rate increases arising as a result of cost allocation changes and individual customer increases arising as a result of rate design. Furthermore, the impacts of each of these factors are, to some extent, considered additive.
- There is general acceptance that cost pressures are likely to lead to year over year increases in average rates.

[26] Order No. P.U. 7 (2002-2003), page 138

- Rate increases in the order of 10% attract significantly more attention and scrutiny with respect to the underlying causes.
- Allowable increases associated with individual customer classes and individual customers should be linked to the average rate increase. However, it is also reasonable to establish limits on the impacts that will be experienced by individual customer classes or customers as a result of changes in cost allocation and rate design.
- With respect to such maximum limits, the values established as being applicable to the specific circumstances in each of the jurisdictions were in the range of 10-20%. Furthermore, the higher values (i.e., 15%-20%) where from jurisdictions where electricity prices have historically been high and/or volatile.

5 CUSTOMERS' PERPSECTIVES ON RATE IMPACTS

5.1 General Observations

At this juncture, there is no readily available empirical data dealing with the attitudes of electricity customers in Ontario as to acceptable levels of bill increases in the current market. The following observations reflect the experience of the Consultants from working both in the rate departments for utilities and for various groups representing customers' interests.

Customers are likely to judge the reasonableness of rate/bill changes from a number of perspectives. One common benchmark is how the proposed increase compares with the changes in the cost for other goods and services as measured by indexes such as the Consumer Price Index (CPI). Table #7 sets out the change in CPI since the market restructuring in 1999.

TABLE 7

Inflation: 1999-2004

Item	October 1999	October 2004	Percent Change
Total CPI	111.5	125.2	12.3% (2.35%/annum)
Core* CPI	113.9	124.7	9.5% (1.83% per annum)

*Core CPI: The CPI excluding the eight most volatile components (fruit, vegetables, gasoline, fuel oil, natural gas, mortgage interest, inter-city transportation and tobacco products) as well as the effect of changes in indirect taxes on the remaining components.

Source: Bank of Canada - http://www.bankofcanada.ca/en/cpi.htm

Another factor likely affecting customers' perspectives with respect to "reasonable rate changes" is their past experience with the prices for the specific service:

- Customers are more likely to accept rate/price increases for services that have a history of volatile behaviour and where the reasons for such behaviour are understood to be driven by external/uncontrollable forces. However, until the volatility trend/pattern has been established and accepted, customers are likely to resist significant repeated increases in rates.
- In contrast, when prices have exhibited a history of stability (in terms of year over year changes) customers are less likely to accept higher rate/bill increases.
- When rates have been fixed for a protracted period or there are cost pressures clearly beyond the control of the utility, customers are likely to be sympathetic to the utility's need for rate increases - even if they are in excess of inflation.
- Customers, however, are likely to exhibit considerable less sympathy for increases that are triggered as a result of events over which the utility and its shareholder (or government as in the case of Crown Corporations) are viewed as having some control.

- In considering the reasonableness of their individual bill increases customers will also consider the rate/bill changes being experienced by other customers. In this regard even a modest increase may be viewed as unreasonable if everyone else's bill is going down.

A good example of some of these considerations is the recent proceeding in Manitoba. The 2001-2003 drought had a significant impact on retained earnings of Manitoba Hydro and the company had not implemented a rate increase[27] for a number of years. Overall, customer groups participating in the proceeding generally recognized and accepted the need to increase rates in order to restore the financial health of the Corporation. However, at the same time, the government had recently provided for "special payments" to the province to be made by Manitoba Hydro and the company's capital spending had increased as a result of recent acquisitions and plans for advancing the construction of new generation. As a result, customers were quite critical of Manitoba Hydro's request and whether the rate increase was actually going to aid in the recovery from the drought or simply fund cost increases at Manitoba Hydro. Overall, their view was that the cost of recovering from the drought should not be borne solely by ratepayers and that internal spending reductions by the utility should also contribute to the solution.

5.2 Recent Electricity Rate Changes in Ontario

In the case of Ontario and electricity, analysis by ECS of a cross-section of LDCs indicates that since 1999 residential customers' bills for monthly use of 1,000 kWh have increased an average of 3.8% per year. More details regarding the average and maximum increases experienced at different consumption levels are set out in Table 8.

[27] Since the mid-1990's increase in revenue from export sales have allowed Manitoba Hydro to avoid the need for seeking rate increases for domestic customers.

TABLE 8

Estimated 1999-2004 Total Residential Bill Increases

Monthly kWh	Annual Average % change 1999-2004	Annual Maximum % change 1999-2004	Annual Minimum % change 1999-2004
250	3.6%	7.2%	-1.0%
500	3.5%	5.3%	0.4%
750	3.4%	4.7%	0.9%
1,000	3.8%	5.1%	1.6%
1,500	4.2%	5.7%	1.6%
2,000	4.5%	6.0%	1.7%

Note: LDCs 1999 Rates obtained from LDC RUD model filings
2004 Rates from OEB decisions
Residential Volumes based on RUD levels

Furthermore, residential customers will experience additional increases in 2005 as result of LDCs being allowed to incorporate in their distribution rates the next (and generally final) instalment of their MBRR. For the same cross-section of LDCs these increases are expected to lead to increases in the total bill of roughly 3%. However, the results will vary by utility and also by consumption level as demonstrated in Table 9**.**

TABLE 9

Estimated 2004-2005 Total Residential Bill Increases

Monthly kWh	Average % change	Maximum % change	Minimum % change
250	5.8%	11.1%	0.0%
500	4.2%	8.2%	0.0%
750	3.4%	6.9%	0.0%
1,000	3.0%	6.0%	0.0%
1,500	2.5%	5.1%	0.0%
2,000	2.2%	4.6%	0.0%

Note: LDCs 2004 rates obtained from OEB decisions
2005 Rates derived with 2002, and 2004 RAM models, and RUD model

Based on these results, it could be argued that residential customers are now acclimatized to average increases in electricity prices in the order of 4% per annum, with individual customers[28] in specific utilities experiencing increases of more than twice this amount.

Finally, it is likely that significant changes in other components of the residential customers' bill will occur, such as the introduction of the government's Regulated Price Plan and the setting of new price effective May 1, 2005 for the commodity portion of the bill. In order to illustrate the total bill impacts that end-use customers may experience, a 5% increase has been assumed for the other components of a residential customer's bill and the results are presented in Table 10. For a customer using 1,000 kWh per month, the average bill impact over the cross-section of LDCs ranges from 3.9% to 9.8% as compared to the 0% to 6% range seen in Table 9.

[28] The highest increases are experienced by low volume customers. At 250 kWh use per month, the maximum dollar increase for the cross-section of LDCs analysed is less than $4/month

TABLE 10

Estimated 2004-2005 Total Residential Bill Increases
Assuming 5% increase in 2005 for Other Charges

Monthly kWh	Average % change	Maximum % change	Minimum % change
250	8.6%	13.8%	2.8%
500	7.6%	11.5%	3.4%
750	7.1%	10.5%	3.7%
1,000	6.8%	9.8%	3.9%
1,500	6.5%	9.1%	4.0%
2,000	6.3%	8.7%	4.1%

Note: LDCs 2004 rates obtained from OEB decisions
2005 Rates derived with 2002, and 2004 RAM models, and RUD model

As result, pending rate/price changes may also shape consumers' perspectives with respect to "reasonable" rate changes for 2006. Further, this analysis demonstrates that the impact of distribution rate changes can not be considered in total isolation.

6 RATE IMPACTS AND THE 2006 EDR PROCESS

6.1 Overall Revenue Requirement

The current draft of the new Electricity Distribution Rate Handbook proposes that the cost of operations and rate base for 2006 be based on 2004 actual costs and rate base with number of specific adjustments where 2005 costs are known (referred to as Tier 1 adjustments)[29]. Similarly, billing quantities used to derive the rates would be based on 2004 customer counts and normalized usage per customer. The ROE and deemed debt rates underlying the determination of an LDC's average cost of capital would also be updated to reflect current financial circumstances. Utilities would be permitted to depart from this approach and make further adjustment to their cost of operations (referred to as Tier 2 adjustments) only under very limited

[29] 2006 Electricity Distribution Rate Handbook-Draft 1, pages 11-14

circumstances[30], which would require substantially more justification and documentation. In the alternative, LDCs will be permitted to file based on a future 2006 test year but this would require a full traditional cost of service rate application.

In contrast, its is expected that the process for setting 2005 rates for Ontario's electricity distributors will likely involve allowing utilities to adjust their current 2004 rates for the recovery of (in most cases) the final one-third of their allowed market based rate of return (MBRR) and associated taxes. This adjustment to revenue requirement and rates is contingent upon the utilities investing the additional MBRR in C&DM programs. However, the costs of operations and the rate base underlying the 2004 rates would remain unchanged from the original 1999 base – with the exception of one small PBR-related adjustment in 2002.

6.1.1 Utilities' Perspective

From discussions in the Working Groups and Stakeholder conferences associated with the 2006 Handbook development process, there are several general considerations that are important to LDCs. For LDCs adopting the Tier 1 approach, as provided for in the current draft Handbook, use of 2004 actual costs and rate base will effectively represent a five-year update in terms of costs and rate base. Indeed, in some cases, the draft 2006 Handbook allows utilities to utilize 2005 costs and in-service assets. While the impact on rates will be offset to some extent by increases in billing quantities (i.e., # of customers and kWhs sold) since 1999, there is still the possibility of a material increase in distribution rates between 2005 and 2006 that could give rise to customer concerns regarding rate/bill impacts.

Indeed, if cost/rate base changes were to simply lead to increases in distribution rates that track inflation the required increase in distribution rates would be in the order of 10% (see Table 7). Added pressures from higher cost/rate base increases through to 2004, the inclusion of some 2005 costs, increases in 2006 in regulatory asset recovery and the allowances for new utility initiatives[31] could all serve to push the required increase in distribution rates for 2006 (over 2005) significantly higher. From a utility's perspective, these costs are "reasonable" –

[30] 2006 Electricity Distribution Rate Handbook-Draft 1, pages 15-17
[31] 2006 Electricity Distribution Rate Handbook-Draft 1, pages 13-14.

particularly since they are based on actual spending and new initiatives that in many cases are driven by government policy.

6.1.2 Customers' Perspective

From the discussion in the Working Groups and Stakeholder conferences, there are several general considerations that are important to ratepayer representatives. Most of these considerations were discussed in Section 5 and suggest that customers' acceptance of the need for LDCs to increase distribution rates to address increases in costs and the addition of assets since 1999 is likely to be tempered by several factors, including the following:

1. Total bills for electricity have increased over the same period and by more than inflation,
2. A significant portion of the most recent (2005/2004) increase in the total electricity bill will have been attributed to an increase in distribution rates.
3. There is a continuing expectation that electricity prices, particularly for the "regulated charges" on a customer's bill are controllable.

As a result, arguments that LDCs have not been allowed any increases in rates to address increasing cost pressures since 1999 will be approached with some scepticism by customers. Furthermore, even if they do prove to hold some sway with customers, increases in excess of inflation are unlikely to be accepted, without further explanation. Indeed, customers are likely to expect utilities to have held their cost increases to less than inflation through cost control measures and efficiency improvements consistent with the objectives of the first generation PBR plan. On this basis, Tables 10 through 12 set out the results of combining inflation over the past 5 years (1999-2004) with various productivity assumptions and applying the resulting escalation factors to the distribution component for estimates of the 2005 rates for the cross-section of LDCs. The results suggest that for a residential customer using 1,000 kWhs per month expectations could be for total bill increases in the order of 3% or less.

TABLE 11

Estimated 2006 Total Residential Bill Increases
Based on 2% Per Annum Increase in Inflation - 10.41%

Monthly kWh	Average % change	Maximum % change	Minimum % change
250	5.0%	6.3%	2.9%
500	3.7%	4.7%	2.0%
750	3.1%	3.9%	1.6%
1,000	2.7%	3.3%	1.4%
1,500	2.2%	2.8%	1.2%
2,000	2.0%	2.6%	1.0%

Note: 2005 Rates derived with 2002, and 2004 RAM models and RUD model

TABLE 12

Estimated 2006 Total Residential Bill Increases
Based on Inflation of 2% Per Annm Offset by 0.5%/annum
Productivity Improvement - 7.73%

Monthly kWh	Average % change	Maximum % change	Minimum % change
250	3.7%	4.7%	2.1%
500	2.7%	3.5%	1.5%
750	2.3%	2.9%	1.2%
1,000	2.0%	2.5%	1.0%
1,500	1.7%	2.1%	0.9%
2,000	1.5%	1.9%	0.8%

Note: 2005 Rates derived with 2002, and 2004 RAM models and RUD model

TABLE 13

Estimated 2006 Total Residential Bill Increases
Based on Inflation of 2% Per Annum Offset by 1.5%/annum
Productivity Improvement - 2.53%

Monthly kWh	Average % change	Maximum % change	Minimum % change
250	1.2%	1.5%	0.7%
500	0.9%	1.2%	0.5%
750	0.7%	0.9%	0.4%
1,000	0.6%	0.8%	0.3%
1,500	0.5%	0.7%	0.3%
2,000	0.5%	0.6%	0.3%

Note: 2005 Rates derived with 2002, and 2004 RAM models and RUD model

6.1.3 Conclusions – Overall Rate Impacts

Differing Expectations

From the foregoing it is clear that there is likely to be a dichotomy between the expectation of utilities (and their shareholders) versus customers in terms of what are considered "just and reasonable" rate increases for 2006. Customers' expectations with respect to increases in total bills are likely range from 2-5%; while distribution rate increase expectations are likely to be - at best - in the order of 8%.

In contrast, even Tier 1 utilities could be seeking increases in distribution rates that are considerably higher than customers' expectations. These differences and concerns are likely to be further heightened for LDCs proposing to incorporate Tier 2 adjustments.

Recognizing that it is the LDCs making the application, one way to address this is to require the filing to include various impact analyses and to also set different information filing requirements for LDCs depending upon the customer bill impact arising from their proposed revenue requirement and rates.

Disclosure and Filing Requirements

The rate impact filing requirements should include:

1. The average increase in distribution rates (i.e., the percentage increase in revenues from applying the proposed distribution rates as opposed to the current distribution rates to the test year billing quantities).
2. The increase in customers' distribution and total bills (over a range of monthly usage values for each customer class) forecast for 2006 assuming all rates increase at the "average increase".

Information filing requirements could then be set depending upon the level of the resulting impacts such that for:

1. For Applications with rate increases that are likely to be consistent with customers' expectations no additional information is required over and above that already requested by the 2006 draft Rate Handbook. These could be referred to as *Category 1 Applications*.

   Based on the foregoing discussion, a reasonable threshold for Category 1 based on a 2004 (adjusted) test year for 2006 rates would be average distribution increases of 8% or less. At this level, total bill impacts for a 1,000 kWhs of residential use monthly would be less than 3% for virtually all utilities across the province – assuming no increases in the other components on a customer's bill.

   In choosing the appropriate thresholds (either here or for the subsequent Categories), it must recognized that the rates/prices associated with other portion of the bill could also change in 2006. As result, while the total bill impact analysis should be done based on "known" rates for the other portions of the bill, a conservative approach should be adopted when selecting the distribution bill impact thresholds to be used and the definition of what constitutes "rate shock".

2. LDCs whose rate impacts do not meet the Category 1 threshold but where the distribution rate increases are not sufficient to be viewed as bordering on rate shock (i.e. 9-10%) could be required to submit a "variance analysis" identifying which of the cost components in their rate applications are the key drivers for the required increase. It is important to note that, at this stage, LDCs would only be required to identify these factors and there would be no need to provide additional discussion unless the LDC itself felt it was warranted or there were follow-up questions during the review of the Application. These could be referred to as *Category 2 Applications*.

   Based on the discussion in Sections 4 & 5, Category 2 Applications could be defined as those that do not meet the Category 1 requirements but where the average increase in distribution costs is less than 16%. At this level, total bill impacts for 1,000 kWhs of residential use per month would be less than 6% for virtually all utilities across the province – assuming no increases in the other components on a customer's bill. Furthermore for lower level of monthly use where the total bill percentage impacts exceed 6%, the absolute bill impact should be less than $5.

3. LDCs whose applications don't meet the threshold requirements for Category 2, but where distribution rate increases are bordering on "rate shock" could be required to provide not only the variance analysis outlined for Category 2 Application but also provide "justification" as to why the level of expenditures incorporated into the test year revenue requirement are required in order to maintain service to customers. These could be referred to as Category 3 Applications. The level of detail sought for Category 3 Applications would be similar to that required to satisfy the Tier 2 Adjustment filing requirements[32].

   Again, based on the discussion in Sections 4&5, Category 3 Applications could be defined as those that do not meet the threshold requirements for Category 2 and where the average

[32] 2006 Electricity Distribution Rate Handbook-Draft 1, pages 16

distribution rate increase is less than 25%. . At this level, total bill impacts for a 1,000 kWhs of monthly residential use would be less than 9% for virtually all utilities across the province – assuming no increases in the other components on a customer's bill. For lower levels of monthly use where the total bill percentage impacts exceed 10%, the absolute bill impact should be less than $8.

4. LDCs whose applications don't meet the threshold requirements for Category 3 would be required to file the information requirements associated with Category 3 (i.e., the variance analysis and supporting justification). They would also be required to provide a discussion as to what efforts, if any, they plan to take to ***mitigate*** the anticipated increase and where/how these plans are reflected in the Application. These could be referred to as Category 4 Applications.

   Mitigation plans could include new/ongoing efforts to reduce costs (through efficiency improvements) relative to those based on 2004 actual results, proposals to defer the cost recovery of specific programs and/or lower net income levels than permitted under the revised Handbook. To the extent that such mitigation plans when reflected in the Application result in the Application falling into either Category 2 or 3, then it should be presented as such with a discussion of the associated mitigation plans.

The following Table summarizes the definitions and requirements for the four impact categories.

TABLE 14

Rate Impact Categories and Filing Requirements

Category	Definition	Filing Requirements
#1	Increase in overall average distribution rates is 8% or less	No additional requirements.
#2	Increase in overall average distribution rates exceeds 8% but is 16% or less	Variance analysis required identifying key drivers underlying increase in distribution rates
#3	Increase in overall average distribution rates exceeds 16% but is 25% or less.	Variance analysis required along with justification for spending level requirements in key areas.
#4	Increase in overall average distribution rates exceeds 25%	Variance analysis and justification required as along with discussion as to what efforts they plan to take to mitigate the anticipated increase and where/how these plans are reflected in the Application

6.2 Cost Allocation and Rate Design

6.2.1 Issues for 2006

In terms of rate design, the Board has determined that the fixed/variable split for each customer class should remain unchanged for 2006 rates[33]. The result is that there is should be very little in the way of rate/bill impacts arising from the rate design changes in the rate applications for 2006. This situation is in marked contrast to that for 2000 when the rate unbundling requirement of the first Handbook and the move to a fixed service charge created the potential for rate/bill impacts for low volume customers. In order to address this, the 2000 Rate Handbook required[34] that

[33] Issues Day, Transcript Volume 3, paragraphs 31-32
[34] 2000 Rate Handbook, page 4-45.

utilities adjust the fixed variable split for their distribution rate structure so as to limit customer bill impacts for low volume customer to 10%.

In terms of cost allocation, the current draft of the 2006 Handbook proposes minimal changes in the allocation of the core distribution revenue requirement to customer classes. In fact, the only real change is the proposal[35] to allocate the revenue loss from the proposed reduction in rates to unmetered and scattered load (part of the <50 kW customer group) to all customer classes. However, the revenue requirement used to establish 2006 rates is likely to include a number of adjustments for new items not included in 2004 costs or 2005, rates such as the recovery of post 2003 year-end Regulatory Assets, the costs of Smart Meters and Conservation and Demand Management expenditures. To the extent decisions are made by the OEB to uniquely allocate any of these costs to customer classes in a manner other than the one that reflects the current overall allocation of distribution revenues across customers classes, differentials in rate/bill impacts for distribution services by customer class will arise. As a result, distribution rate/bill impact differentials across customer classes from cost allocation may arise and need to be addressed.

Finally, a number of utilities are currently facing the situation where, as a result of mergers/acquisitions or the carry over of legacy rate class from the pre-restructuring period, there exists two or more rate schedules that the LDC would like to harmonize. Such harmonization does not change the total revenue requirement for the utility but does result in rate/bill impacts for individual customers as customers are moved to a "common" rate schedule. In the first Handbook, the OEB required[36] that the impacts of harmonization be limited to 5% per annum.

As noted in the earlier discussion, changes in cost allocation and rate design involve trade-off between the interests of various customers.

[35] 2006 Electricity Distribution Rate Handbook-Draft 1, pages 80-81
[36] HB Reference

6.2.2 Conclusions – Class and Customer Rate Impacts

There could well be variations in the average rate/bill increases attributable to each customer class or individual customer. In order to highlight the potential impacts, LDCs should required to include in their Applications impact analyses at both the customer class and individual customer level. LDCs should work to limit the impacts associated with cost/allocation and rate design to acceptable levels.

Filing Requirements

To this end, the rate/bill impact-related filing requirements for each customer class should include:

1. The average increase in distribution rates for each customer class (i.e., the percentage increase in revenues from applying the proposed distribution rates as opposed to the current distribution rates to the test year billing quantities), prior to any rate harmonization.
2. The increase in individual customers' distribution and total bills (over a range of monthly usage values for each customer class) forecast for 2006 based on the cost allocation/rate design as proposed by the LDC, prior to any rate harmonization.
3. For those classes where rate harmonization (partial or full) is proposed, the increase in customers' distribution and total bills (over a range of monthly usage values for each customer class) forecast for 2006 based on the "harmonized" rates proposed by the LDC.

Rate Impact Guidelines

The revised Rate Handbook should include impact guidelines that limit the average increase in each customer class' distribution rates relative to the proposed all customer average distribution rate increase as follows:

1. The increases in a customer class' average distribution rates due to cost allocation changes and harmonization should be limited to the all customer average increase (i.e., the maximum customer class increase would be double the all customer average increase).
2. In addition the following total bill impact considerations should apply:

a. For those situations where increases in the total bills for individual customers in a rate class, based on the overall average distribution rate increase for the LDC, is less than or equal to the greater of 9% or $5 / month, the maximum bill impact should be limited to 9.5%.
b. For those situations where increases in the total bills for individual customers in a rate class, based on the overall average distribution rate increase for the LDC, is over 9%, the bill impacts arising from cost allocation changes should be limited to 0.5%.

6.3 Final Comments/Observations

The preceding recommendations with respect to filing requirements and rate impact guidelines provide a framework for incorporating rate impact considerations into the 2006 Rate Handbook. However, the framework can not, in itself, answer the question as to whether the revenue requirement and proposed customer rates included in a particular application represents a fair balance between a) the interests of utility shareholders for opportunity to earn a fair rate of return on their investments and b) the interests of customers for rates that are based on prudently incurred costs and do not create rate shock or financial hardship.

Inevitably achieving this balance is a matter of judgment which the OEB is required to exercise. Such judgment will need to take into account not only filing requirements/guidelines such as outlined here but also the particular circumstance of the LDC concerned and the ever changing conditions of Ontario's electricity market.

APPENDIX A

DEVELOPMENT OF LDC CROSS-SECTION

The implications of distribution rate increases on an individual customer's total bill depend on both the customer's level of consumption and the specific LDC concerned. Furthermore, to determine these implications it is necessary to access, for each LDC concerned, the data and documentation associated with a number of different rate approvals including the 1999 RUD, the 2002 RAM and the 2004 RAM. In order to facilitate the analyses of distribution rate impacts, it proved desirable to develop a representative cross section of Ontario's LDCs.

Set out below are the steps used ECS to select a cross-section of LDC for purposes of this report:

- The current rates currently charged by each of existing LDCs in the province for distribution and other services were obtained from OEB Staff, with the understanding that the rates would require further verification.
- The LDCs were then all ranked lowest to highest, based on the cost of distribution that would be charged to a residential customer using 1,000 kWh per month and it was decided that the cross-section should consist of roughly 25 utilities (i.e. 1 in 4).
- On this basis, every fourth LDC in the ranking was selected with the following exceptions:
    - In those cases where there had been an amalgamation or merger involving the LDC between 1999 and 2004, the LDC was excluded and one with a similar distribution cost was substituted.
    - In those cases where the utility had more than one residential rate (e.g., suburban and urban), the LDC was excluded and one with a similar distribution cost was substituted.
    - In those cases where problems were experienced with the initial data collection (e.g., unavailability of 1999 RUD models), the LDC was excluded and one with a similar distribution cost was substituted.
- To the resulting list of LDCs a small number of the large LDCs in province who had not been captured in the selection were added. This was done in order to ensure that the

analyses also reflected the rates chargeable to a large number of the customers in the province resulting in cross-section consisting of 28 LDCs.

- The accuracy rates provided by OEB staff for the selected LDCs were checked
- A small number of the LDCs had to be dropped (without replacement) when major data problems were identified later on in the analyses.
- Also, for some of the individual analyses presented, specific LDCs had to be excluded due to minor data availability problems.

A list of the LDCs included in the cross-section is set out below:

1. Atikokan Hydro Inc.
2. Aurora Hydro Connections Ltd.
3. Brantford Power Inc.
4. ELK Energy Inc.
5. Enersource Hydro Missisauga Inc.
6. Guelph Hydro Electric System Ltd.
7. Halton Hills
8. Hearst Power Distribution Co. Ltd.
9. Hydro Vaughan Dist. Inc.
10. Innisfil Hydro Distribution
11. Kingston Electricity Distribution Ltd.
12. Kitchner Wilmot Hydro Inc.
13. London Hydro Utilities Services Inc.
14. Markham Hydro Distribution Inc.
15. Middlesex Power Distribution Corp.
16. Newmarket Hydro Inc.
17. North Bay Hydro Distribution Ltd.
18. PUC Distribution Inc.
19. Renfrew Hydro Inc.
20. Richmond Hill Hydro Inc.
21. Sioux Lookout Hydro Inc.

22. St. Catherines Hydro Utilities Services Inc.
23. St. Thomas Energy Inc.
24. Wasaga Distribution Inc.
25. Welland Hydro Electric System Corp.
26. West Nipissing Energy Services Ltd.
27. West Perth Power Inc.
28. Woodstock Hydro Services Inc.

APPENDIX B

CVs FOR ECS CONSULTANTS

William O. Harper

Mr. Harper has over 20 year experience in the design of rates and the regulation of electricity utilities. He has testified as an expert witness on rates before the Ontario Energy Board from 1988 to 1995, and before the Ontario Environmental Assessment Board. He was responsible for the regulatory policy framework for Ontario municipal electric utilities and for the regulatory review of utility submissions from1989 to 1995. Mr. Harper coordinated the participation of Ontario Hydro (and its successor company Ontario Hydro Services Company) in major public reviews involving Committees of the Ontario Legislature, the Ontario Energy Board and the Macdonald Committee. He has served as a speaker on rate and regulatory issues for seminars sponsored by the APPA, MEA, EPRI, CEA, AMPCO and the Society of Management Accountants of Ontario. Since joining ECS, Mr. Harper has provided consulting support for client interventions on energy and telecommunications issues before the Ontario Energy Board, Manitoba Public Utilities Board, Québec's Régie de l'énergie, British Columbia Utilities Commission, and CRTC. He has also appeared before the Manitoba's Public Utilities Board, the Manitoba Clean Environment Commission and Quebec's Régie de l'énergie. Bill is currently a member of the Ontario Independent Electricity Market Operator's Technical Panel.

EXPERIENCE

Econalysis Consulting Services- Senior Consultant
2000 to present

- Responsible for supporting client interventions in regulatory proceedings, including issues analyses & strategic direction, preparation of interrogatories, participation in settlement conferences, preparation of evidence and appearance as expert witness (where indicated by an asterix).

- Electricity
    - IMO 2000 Fees (OEB)
    - Hydro One Remote Communities Rate Application 2002-2004
    - OEB - Transmission System Code Review (2003)
    - OEB - Distribution Service Area Amendments (2003)
    - OEB – Regulated Asset Recovery (2004)
    - BC Hydro IPP By-Pass Rates
    - WKP Generation Asset Sale
    - BC Hydro Heritage Contract Proposals
    - BC Hydro's 2004/05 and 2005/06 Revenue Requirement Application
    - BC Transmission Corporation – Open Access Transmission Tariff Application - 2004
    - BC Hydro's CFT for Vancouver Island Generation - 2004
    - Hydro Québec-Distribution's 2002-2011 Supply Plan*

- Hydro Quebec-Distribution’s 2002-2003 Cost of Service and Cost Allocation Methodology*
- Hydro Québec-Distribution’s 2004-2005 Tariffs*
- Hydro Québec – Distribution’s 2005/2006 Tariff Application*
- Manitoba Hydro’s Status Update Re: Acquisition of Centra Gas Manitoba Inc.*
- Manitoba Hydro’s Diesel 2003/04 Rate Application*
- Manitoba Hydro’s 2004/05 and 2005/06 Rate Application*
- Manitoba Hydro/NCN NFAAT Submission re: Wuskwatim*

- Natural Gas Distribution
  - Enbridge Consumers Gas 2001 Rates
  - BC Centra Gas Rate Design and Proposed 2003-2005 Revenue Requirement
  - Rate of Return on Common Equity (BCUC)
  - Terasen Gas (Vancouver Island) LNG Storage Project (2004)

- Telecommunications Sector
  - Access to In-Building Wire (CRTC)
  - Extended Area Service (CRTC)
  - Regulatory Framework for Small Telecos (CRTC)

- Other
  - Acted as Case Manager in the preparation of Hydro One Networks’ 2001-2003
  - Distribution Rate Applications
    - Supported the preparation of Distribution Rate Applications for various Ontario municipal electric utilities.
  - Supported the implementation of OPG’s Transition Rate Option program prior to Open Access in Ontario
  - Prepared Client Studies on various issues including:
    - The implications of the 2000/2001 natural gas price changes on natural gas use forecasting methodologies.
    - The separation of electricity transmission and distribution businesses in Ontario.
    - The business requirements for Ontario transmission owners/operators.
    - Various issues associated with electricity supply/distribution in remote communities

Hydro One Networks
Manager - Regulatory Integration, Regulatory and Stakeholder Affairs
(April 1999 to June 2000)

- Supervised professional and administrative staff with responsibility for:
  - providing regulatory research and advice in support of regulatory applications and business initiatives;
  - monitoring and intervening in other regulatory proceedings;
  - ensuring regulatory requirements and strategies are integrated into business planning and other Corporate processes;

    - providing case management services in support of specific regulatory applications.
- Acting Manager, Distribution Regulation since September 1999 with responsibility for:
    - coordinating the preparation of applications for OEB approval of changes to existing rate orders; sales of assets and the acquisition of other distribution utilities;
    - providing input to the Ontario Energy Board's emerging proposals with respect to the licences, codes and rate setting practices setting the regulatory framework for Ontario's electricity distribution utilities;
    - acting as liaison with Board staff on regulatory issues and provide regulatory input on business decisions affecting Hydro One Networks' distribution business.
- Supported the preparation and review before the OEB of Hydro One Networks' Application for 1999-2000 transmission and distribution rates.

Ontario Hydro
Team Leader, Public Hearings, Executive Services (APR. 1995 TO APR. 1999)

- Supervised professional and admin staff responsible for managing Ontario Hydro's participation in specific public hearings and review processes.
- Directly involved in the coordination of Ontario Hydro's rate submissions to the Ontario Energy Board in 1995 and 1996, as well as Ontario Hydro's input to the Macdonald Committee on Electric Industry Restructuring and the Corporation's appearance before Committees of the Ontario Legislature dealing with Industry Restructuring and Nuclear Performance.

Manager – Rates, Energy Services and Environment (June 1993 to Apr. 95)
Manager – Rate Structures Department, Programs and Support Division (February 1989 to June 1993)

- Supervised a professional staff with responsibility for:
    - Developing Corporate rate setting policies;
    - Designing rates structures for application by retail customers of Ontario Hydro and the municipal utilities;
    - Developing rates for distributors and for the sale of power to Hydro's direct industrial customers and supporting their review before the Ontario Energy Board;
    - Maintaining a policy framework for the execution of Hydro's regulation of municipal electric utilities;
    - Reviewing and recommending for approval, as appropriate, municipal electric utility submissions regarding rates and other financial matters;
    - Collecting and reporting on the annual financial and operating results of municipal electric utilities.
- Responsible for the development and implementation of Surplus Power, Real Time Pricing, and Back Up Power pricing options for large industrial customers.
- Appeared as an expert witness on rates before the Ontario Energy Board and other regulatory tribunals.

- Participated in a tariff study for the Ghana Power Sector, which involved the development of long run marginal cost-based tariffs, together with an implementation plan.

Section Head – Rate Structures, Rates Department
November 1987 to February 1989

- With a professional staff of eight responsibilities included:
  - Developing rate setting policies and designing rate structures for application to retail customers of municipal electric utilities and Ontario Hydro;
  - Designing rates for municipal utilities and direct industrial customers and supporting their review before the Ontario Energy Board.
- Participated in the implementation of time of use rates, including the development of retail rate setting guidelines for utilities; training sessions for Hydro staff and customers presentations.
- Testified before the OEB on rate-related matters.

Superintendent – Rate Economics, Rates and Strategic Conservation Department
February 1986 to November 1987

- Supervised a Section of professional staff with responsibility for:
  - Developing rate concepts for application to Ontario Hydro's customers, including incentive and time of use rates;
  - Maintaining the Branch's Net Revenue analysis capability then used for screening marketing initiatives;
  - Providing support and guidance in the application of Hydro's existing rate structures and supporting Hydro's annual rate hearing.

Power Costing/Senior Power Costing Analyst, Financial Policy Department
April 1980 to February 1986

- Duties included:
  - Conducting studies on various cost allocation issues and preparing recommendations on revisions to cost of power policies and procedures;
  - Providing advice and guidance to Ontario Hydro personnel and external groups on the interpretation and application of cost of power policies;
  - Preparing reports for senior management and presentation to the Ontario Energy Board.
- Participated in the development of a new costing and pricing system for Ontario Hydro. Main area of work included policies for the time differentiation of rates.

Ontario Ministry of Energy
Economist, Strategic Planning and Analysis Group
April 1975 to April 1980

- Participated in the development of energy demand forecasting models for the province of Ontario, particularly industrial energy demand and Ontario Hydro's demand for primary fuels.
- Assisted in the preparation of Ministry publications and presentations on Ontario's energy supply/demand outlook.

- Acted as an economic and financial advisor in support of Ministry programs, particularly those concerning Ontario Hydro.

EDUCATION

Master of Applied Science – Management Science

- University of Waterloo, 1975
- Major in Applied Economics with a minor in Operations Research
- Ontario Graduate Scholarship, 1974

Honours Bachelor of Science

- University of Toronto, 1973
- Major in Mathematics and Economics
- Alumni Scholarship in Economics, 1972

Joyce Poon

Joyce Poon has a thorough knowledge of the energy industry based on 16 years of work experience. Prior to joining ECS, Joyce's responsibilities, related to the upstream pipeline, marketing and distribution provided her with a "big picture" perspective of the market. In the areas of rate design and forecast models, she has written evidence and testified before regulatory boards on behalf of natural gas utilities (Enbridge Consumers Gas, and Centra Gas Ontario), in addition to handling day-to-day managerial responsibilities. At ECS, Joyce provides on-going support to intervenors at energy and insurance proceedings and assists corporate clients in preparing applications to regulatory boards.

EXPERIENCE

Econalysis Consulting Services- Senior Consultant
1999 to present

- Responsible for providing strategic direction and analytical expertise for client intervention in regulatory proceedings, by drafting interrogatories, position papers, expert evidence, cross-examination, and final argument.

- Electricity
  - OHNC Transmission 2000 Cost Allocation and Rate Design (OEB)
  - Hydro One Networks Inc. – Distribution Rates (RP-2000-0023)

- Natural Gas
  - BC Gas Annual Review for the 2000 and 2001 Revenue Requirement, and assistance in review of a BC Gas comprehensive PBR proposal
  - Terasen Gas Inc. and Terasen Gas Vancouver Island Annual Review for 2004
  - Centra Gas Manitoba Inc. -1999/2000 Cost of Gas Rate Increase Application
  - Centra Gas Manitoba Inc. – Primary Gas Price Applications
  - Centra Gas Manitoba Inc. – 2003/04 Test Year Rates Application
  - Centra Gas Manitoba Inc. – Proposed Acquisition of Assets of Gladstone
  - Centra Gas Manitoba Inc. – 2004/05 Cost of Gas Application
  - SCGM- 2000 Rate Case
  - SCGM- Unbundling Case
  - Pacific Northern Gas Ltd. –2000, 2001, 2003, and 2004 Revenue Requirements Application to the BCUC
  - Natural Gas Pipeline to Proposed Brighton Beach Power Station (co-authored evidence)
  - Union Gas PBR and Unbundling Application (RP-1999-0017)

- Union Gas Enabling Unbundling (RP-2000-0078)
  - Union Gas Motion on the RP-1999-0017
  - Union Gas 2001 and 2002 Customer Review
  - Union Gas 2003 Rates (co-authored evidence and testified)
  - Union Gas 2004 Rates
  - Union Gas QRAM Application (EB-2003-056)
  - Enbridge Consumers Gas - 2001 Rate Application
  - Enbridge Consumers Gas – 2002 Rate Application
  - Enbridge Consumers Gas –2003 Rate Application
  - Enbridge Consumers Gas – 2005 Rate Application

- <u>Telecommunications Sector</u>
  - Manitoba Telecom Service Inc. – Recovery of 2000 and 2001Income Tax Expense (CRTC 2000-108) (co-authored evidence)

- <u>Other</u>
  - Manitoba Public Insurance – 2001, 2002, 2003, 2004 and 2005 Rate Applications
  - ICBC 2004 Revenue Requirement Application
  - ICBC 2005 Financial Allocation Proceeding
  - Comments on Behalf of Vulnerable Energy Consumers Coalition for:
    - OHNC Transmission PBR Workshop
    - Retail Settlement Code
    - Draft Guidelines for the Interpretation of Electricity Distribution Activities under Section 71 of the Ontario Energy Board Act, 1998.
    - Natural Gas Forum
  - Assisted in developing a "Collaborative Efficiency Management Study" for three Municipal Electricity Utilities
  - Corporate client assignments include developing rate design, and drafting application for filing with regulatory board
    - Completed Corporate Rate Design Applications for numerous Municipal Electric Distribution Utilities in Ontario.
  - Ongoing rate design support for Ontario Local Distribution Companies

Enbridge Consumers Gas
Manager, Rate Design - Regulatory Affairs (1997 to 1999)

- Responsible for drafting evidence and testifying on the area of rate design for Enbridge Consumers Gas, and Gazifere Inc. before the OEB and the Regie, respectively.
- Direct and supervise senior rate design analysts.
- Participated in development of the market design task force evidence regarding unbundling of rates.
- Responsible for modeling the existing rates, and developing modifications or new rates for Enbridge Consumers Gas, and Gazifere Inc.

Regulatory Analyst -Upstream Regulatory Proceedings (1995 to1997)

- Represented the interest of Enbridge Consumers Gas at the TCPL Tolls Task Force.

- Provided analysis, and suggested positions the Company should take on Task Force Issues -provided support in developing the Company's position in various regulatory proceedings, this process included drafting interrogatories and argument.
- Prepared the Upstream Regulatory Department Budget, Variance Analysis, and Evidence used in the Company's Rate Application.
- Assisted in the negotiation of TQM's Multi- Year Tolls Agreement, which has been approved by the NEB.

Centra Gas Ontario
Supervisor, Economics and Demand Forecast Group (1993 to 1995)

- Responsible for drafting evidence and testified before the OEB regarding Centra's Regional Economic Outlook, and Throughput Forecast (testified in EBRO 489).
- Made formal presentations to the president of Centra Gas Ontario and Senior Management on the Economic Outlook for US, Canada, Ontario, and Centra's Regional Franchise Area.
- Directed, and supervised the work of DSM Analysts, Economic Analysts, and Contract Analyst.
- Responsible for producing residential, commercial and industrial throughput forecasts (Budget, 20 YR. DSM and Strategic Plan filed in company's Rate Case).
- Planned and directed the work to monitor and evaluate Demand Side Management Programs.
- Responsible for load research and end-use modeling efforts for Centra Gas Ontario.

TransCanada Gas Services Limited
Senior Marketing Analyst (1992 to 1993)

- Provided analytical support and research to the Director of Marketing during contract negotiations, hearings, and arbitrations.
- Drafted the producer letter requesting a price change for TCGS's second largest customer.
- Developed negotiation strategies with V .P .of Marketing, Director of Marketing, and Manager of Northeast Sales.
- Created and proposed possible gas price indexes for new and existing customers.
- Monitored the effects of Order 636 on TCGS's Northeast Contracts.

LDC Marketing Analyst (1989 to 1992)

- Responsible for hiring and supervising the co-op student for the Marketing, Research and Forecasting Group.
- Monitored the natural gas industry regarding pricing trends and changes resulting from regulatory orders.
- Initiated the improvement of TCGS’ forecasting system.
- Developed a model to forecast all of TCGS' firm long-term export contracts for the purpose of supporting the company during price negotiations and arbitration.
- Generated long-term domestic and export sales forecasts required for budgeting, strategic planning, and RR/P notices.
- Assisted in developing the Strategic Planning Document.

Assistant Market Analyst (1988 to 1989)

- Revised the energy-pricing model into a separate annual and quarterly model.
- Analyzed energy pricing trends through generating pricing reports.
- Produced the long-term energy price forecasts that were filed in the 1989/90 and 1990/91 TCPL Facilities Applications.
- Responded to NEB information requests and undertakings.
- Coordinated and completed the internal report entitled Economic and Financial Forecast Factors.

Canada Systems Group
Financial Analyst (1987 to 1988)

- Co-wrote a report on the integration of the mutual fund system to the existing order network system.
- Developed and prepared financial models and monthly bills.
- Analyzed movements of revenue and expense accounts.

Ontario Ministry of Energy
Research Assistant (1986 and 1987)

- Co-authored a paper entitled "Energy Use By Ontario Manufacturing Industry. 1972 -84" published in the International Association of Energy Economists Journal.
- Rectified and expanded an existing database.
- Performed economic regression analysis on energy price effects on Ontario manufacturing industries.
- Conducted research and literature synopses for the preparation of a provincial contingency plan for oil shortages.
- Wrote standard operating procedures to be used for the oil contingency plan -developed and computerized internal government review forms.

Education

Masters of Arts - Economics
University of Waterloo, Applied Economic Program (1989)

Honours Bachelor of Arts
University of Waterloo, Honours, Economics Major & Psychology Minor
(1986)

Other Courses, include:

- Dale Carnegie Course (1992)
- Canadian Securities Course (1991)