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Ontario Energy Board
26th Floor
2300 Yonge Street
Toronto, Ontario
M4P 1E4
ATT: Mr. John Zych, Secretary

December 20, 2004
Dear Mr. Zych,

RP- 2004 - 0188
In the matter of the Ontario Energy Board Act, 1998 S.O. 1998 c15 Schedule B;
And in the matter of the preparation of handbook for electricity distribution rate applications
ECMI Evidence for Procedural Order No. 2, Schedule B
Conservation and Demand Management – Loss Factor Incentives

In accordance with the OEB's Procedural Order No. 2 dated November 25, 2004, the ECMI coalition (ECMI) hereby submits its evidence with respect to Schedule B of the above noted Procedural Order on conservation and demand management: Loss Factor Incentives.

As requested, eight hard copies and one electronic copy of this evidence are enclosed for the Board Secretary and one electronic copy has been provided to Keith Ritchie by e-mail.

Respectfully submitted for the OEB's consideration.

Roger White
President

The following is the evidence prepared by Roger White, a principal of ECMI. Appended at the end of this evidence is the CV of Roger White.

At the time of preparation of this evidence, there are at least four alternatives which should be considered with respect to Loss Factor Incentives:

Alternative 1:

Status quo where losses remain a pass through with no direct incentive to the LDC to reduce losses.

Alternative 2:

Fix the losses based on a 3 year average moving to 5 years and the shareholder will incur the consequences (gain or loss) flowing from that decision. Under this alternative the variance account would be eliminated.

Alternative 3

The LDC receives an incentive based on the Total Resource Cost Test and receives an incentive above the normal return of the LDC. This is effectively a Shared Savings Mechanism.

Alternative 4:

No specific incentive to the utility, save and except the assurance that any investment made flows into the rate base and the utility is allowed a return on it which would be timely and independent of any generic rebasing.

Introduction

Losses in the electricity system vs. losses in the gas system

It should be recognised that one of the fundamental differences between gas and electricity is that electricity losses include the “fuel” required to push the commodity in addition to leakage (however caused). When one puts pressure in a pipe the pressure remains until the gas is used or removed. Gas has losses from “leakage” only. When voltage is applied to a wire there is no inertia or storage effect. Losses from an electricity system have two dimensions: -

- Fixed losses from energizing the system
- Variable loss from the amount of energy consumed (throughput).

The only way fixed losses can be removed from an electrical distribution system is by physically disconnecting those elements of the distribution system from the source of power. Variable energy losses are generally a function of the square of the current used to deliver energy through the system to the consumer.

Like the gas industry, electric LDC’s are largely demand takers, that is, they meet customer demand but do not determine it directly but often hope to influence demand. Examples of this can include the water heater or other load control systems.

External Considerations

An LDC has no or little short run direct control over some of the electrical losses included in the customer’s bill. For instance, where Hydro One Networks (HONI) has an LV facility outside an LDC, it has OEB approval to apply a loss factor of 3.2% to deliveries through that facility. Similarly, Transformer Stations not owned by an LDC, (generally owned by HONI Transmission) may be changed or modified by the owner and this may impact on the LDCs loss factors. Further, these loss factors may be changed through a process over which the LDC has no direct control.

Losses due to poor factor

Losses due to poor factor are largely out of the control of the LDC because they usually result from customer side of the meter equipment. The customer side of the meter is the best place to fix power factor because it fixes everything up stream of it. One of the most effective ways to provide a customer incentive to fix power factor for demand billed customers is to bill on KVA as Toronto Hydro does.

Changes

New loads or increases in loads often occur at the ends of lines (high loss), thereby increasing an LDCs average losses. Likewise, the loss of an existing major customer near a Transformer Station or other delivery point to the LDC would also increase the LDCs average losses. For an LDC with high industrial growth near its delivery point (low loss), average losses would generally reduce.

Appendices 1 and 2 illustrate the potentially major impacts that the loss or gain of a major customer or the addition or loss of a merchant generator could reasonably be expected to have on an LDC. Appendix 1 deals with the loss of a major customer but the numbers would be symmetrical for the gain of a major customer. Appendix 2 deals with the gain of a merchant generator, but the impact would be symmetrical for the loss of a merchant generator.

Appendix 1 deals with the loss of a major customer for a live utility and examines the universal loss factor versus the likely range of actual losses under Scenarios 1 & 2. There is a comparison of what the loss factor and the actual losses for a relatively low loss customer (Scenario1) and a relatively high loss customer (Scenario 2). For each of these scenarios, three alternate average commodity price implications are included; price 1 at 5.0 cents/KW.h; price 2 at 5.5 cents/KW.h; price 3 at 6.0 cents/KW.h. The last line of each data block shows the adverse impact of the loss of a major customer as a percentage of the shareholder's deemed component of full MARR. Under Scenario 1 considerations it is a relatively low loss customer. The adverse impacts range from 14.8% to 17.8% of full MARR. Under the scenario 2 considerations for the loss of a high loss customer, the benefit to the utility ranges from 5.6% to 6.7% of full MARR.

Appendix 2 deals with the gain of a small merchant generator and the potential impact on the average losses that a utility would experience as a result of a change in losses due to the merchant generator's connection on the low voltage side of the utility's distribution station. Low voltage (44kV) system line losses would be reduced and distribution station losses would be eliminated so an impact of minus 3% associated with the energy delivered by the merchant generator is plausible. Under price 1, a price of 5.0 cents / kW.h is used, under price 2, a price of 5.5 cents / kW.h is used and under price 3, a price of 6.0 cents / kW.h is used. For each of these price alternatives, available energy from the generator is considered using 100% reliability, 80% reliability and 50% for the merchant generator. Under the 100% reliability, the range in benefit is from 21.9% to 26.3% of the shareholder's deemed full MARR. Similarly the range for 85% reliability is 17.5% to 21.0%. At 50% reliability the range is from 11.0% to 13.1%. For the loss of a merchant generator, these positive impacts would be adverse and symmetrical.

If a C& DM program was introduced in a high density low loss environment and if the result of the program was reduced losses in the high density area, then the LDCs average electrical loss would increase due to the increased proportion of losses from the low density (high loss) areas of its service area. This is a result of an increase in the proportion of the utility's losses that are fixed (independent of energy use).

It should be recognised that the system wide planning horizon for LDC's is long with typically 5 years for major capital items and may be as long as 25 years for all ongoing programs. If an LDC were to go out today to replace its system to reduce losses customers would not be prepared to pay the price of such an initiative. The scale of capital investment activity would be similar to the frequency standardisation initiative in the late 1940's and early 1950's. It is therefore not appropriate to expect LDCs to implement major changes in their investment programs, including C & DM, at short notice.

Potential results of implementing each of the four alternatives

Alternative 1

Status quo where losses remain a pass through with no direct incentive to the LDC to reduce losses

Advantages

It is an existing system and does not create some of the apparent disadvantages of some of the other alternatives considered

Disadvantages

There appears to be no direct incentive for LDCs to invest in loss reduction

Alternative 2

Fix the losses based on a 3 year average moving to 5 years and the shareholder will incur the consequences of any gain or loss flowing from the consequences of that the decision. Under this alternative the variance account would be eliminated.

The consequences of going with a fixed loss factor based on the average cost of commodity, is a misnomer. What is being fixed as a consequence of this action is the price of the losses not the losses themselves. The effect of fixing the price is that the customer underpays when the market electricity price is most expensive and overpays when the market price of electricity is less expensive.

Price Signal

If electrical losses are part of Distribution Services then there is no clear incentive to reduce losses because these are part of the regular return to the shareholder/ investor.

Further, to roll electrical losses into distribution system costs would be in direct conflict with the Government's objective that the use of the commodity should reflect the cost of the commodity at the customer's location and the current loss factor does that most effectively on a real time basis as opposed to some adjustment which may happen after the fact because a fixed adjustment which applies regardless of when the commodity is used or what the time sensitive cost of the commodity may be. Applying a utility specific cap as part of the distribution cost (charge) further disconnects from customer real time use because distribution costs are not time sensitive.

There is also the increased possibility of larger deferral accounts and inter-generational transfers.

The commodity cost over the past three years demonstrates that the commodity price would be so variable as to make a forecast arbitrary and inaccurate at best, substantively increasing LDC risk.

A partial RPP Plan

Not all customers are on the RPP plan. Among those not included are large customers, interval metered accounts, or customers who do not qualify to participate in the plan.

Customers who are on the RPP

If the government or the OEB decides to use an inclining price structure, then it should be recognised that the use of the average for the cost of losses on a cents/ kW.h basis would dilute the effectiveness of the price signal as a primary conservation tool.

Under the proposed regime, that loss factor would be buried in distribution rates and would be uniform and that separates the price of losses from the price of the commodity. As the use of smart meters increases, the likely result is that LDCs will experience a shift in load towards off peak. This assumes that there is some elasticity in the use of electricity and that off peak energy will continue to be less expensive than peak energy.

Customers who are not on RPP

However, for customers who are already on real time pricing (spot market), the use of a uniform loss factor is in direct opposition to the stated objective of having the customers pay the actual cost of electricity. One of the potential benefits of the smart meter initiative is to provide real time pricing and the use of a uniform loss factor is in direct opposition to this benefit. Customers that are not on the RPP will face a loss factor under the current regime.

If the OEB decides to use a fixed loss factor and an associated fixed price as suggested in Alternative 2, almost all of the time that loss factor would be applied to the wrong price (different from the true commodity price). The impact of converting to a fixed loss factor is to fix the commodity price.

Under the current regime, there are few smart meters in use by residential customers in the province. As customers migrate from an RPP to a smart meter program, the time of day at which they use commodity is likely to change because its use will be time sensitive ands customers will be seeking bill reductions.

Migration of customers

If customers choose the option to go from RPP to smart meters, they will be migrating from a subsidised to a non-subsidised supply. The migration of the customer from the RPP to spot market increases the utility price risk due to the migration of customers. This migration results in the loss of the fixed price aspect of the RPP and any estimated losses and their associated cost which would have been included in any estimated distribution charge change to replace the use of a loss factor.

Creation of a subsidy

If the loss factor is buried in distribution rates as proposed, this could create a new subsidy.
For instance, an industrial customer with a 1 or 2 day shift process largely pays the cost of losses commensurate with losses during peak periods. If the loss factor is buried in distribution rates, the result is a transfer of cost from the large use customer to residential customers who may be less peak oriented. The result is a subsidy provided to the large use customers by residential customers. For street lighting, the subsidy is obvious and apparent, because the energy used is almost universally off peak and therefore at a lower unit cost. In this latter case, the subsidy is particularly unfair.

Alternative 3
The LDC receives an incentive based on the Total Resource Cost Test and receives an incentive above the normal return of the LDC. This is effectively a Shared Savings Mechanism

The establishment of the appropriate level of Shared Savings benefit might be difficult. The initial level of 5% may be insignificant compared to the capital investments that may be required to achieve loss reduction. A more appropriate test may be a shorter term pay back period for the customers if the benefits of the loss reduction flow to those customers through the use of a reduced loss factor or the variance account. Any shared savings benefit should be outside of the normal return considerations established by the regulator.

Advantages
Can be used to provide an incentive for cash strapped LDC's.

Disadvantages
A Shared Savings Mechanism may be best of all options but might be difficult to separate the loss reduction investment from normal capital expenditure.

Alternative 4
No specific incentive to the utility, save and except the assurance that any investment made flows into the rate base and the utility is allowed a return on it which would be timely and independent of any generic rebasing.

Advantages
Simple, assuming that the price implications of rate base adjustment mechanism can be readily established.

Disadvantages
Similar to the Shared Savings Mechanism (Alternative 3) it may be difficult to separate the loss reduction investment from normal capital expenditure. Also, it may not address the need of cash strapped utilities.

Conclusions

The recognition that the level of losses over which the utility has direct control are significantly a result of the legacy of its existing system. The physical plant reflecting the LDCs investment over time are a physical reality and limitation on the LDCs influence or ability to change losses. The normal life of the LDCs distribution assets is commonly recognised at about 25 years. Premature retirement of these assets would require a major infusion of capital in the system. Time horizons for change range from 5 to 25 years.

An alternative not considered is the adoption of the gas model. It may be appropriate to apply a SSM to the "leakage" part of the electrical losses but it is not appropriate to apply the entire concept in the gas industry in part because of the virtual impossibility of separating the "push" losses from the "leakage" losses for the electricity industry.

The majority of the incremental risks flow from Alternative 2. The consequences of going with a fixed loss factor based on the average cost of commodity, is a misnomer. What are being fixed as a consequence of this action are both the losses and the price of the losses. Contributing risk factors affecting both volume and price are discussed in the previous evidence. They include: -

Distribution system customer mix (loss or gain)
Distributed generation and embedded generation risk (loss or gain)
Conservation & Demand Management (C & DM) program (loss of gain)
Regulated Price Plan customer migration risk

Other risks

Inter-generational

If customers migrate from the RPP to a smart meter situation, customer's risk may increase due to increased or reduced rates as they are leaving the shelter of a fixed price program.

It is ECMI's view that neither an LDC nor its customers should win or lose by pure luck on an item as important and material as losses.

Recommendations

ECMI's recommendations with respect to each of the four alternatives are as follows: -

Alternative 1

Status quo does not provide LDCs with any incentive to reduce losses. This alternative is acceptable.

Alternative 2

It is ECMI's opinion that Alternative 2 should not be considered as it materially increases the risk to the distribution company.

Alternative 3

If the Board wishes to incent loss reduction, a Shared Savings Mechanism may be best of all options but might be difficult to separate the loss reduction investment from normal capital expenditure. This alternative is acceptable but may be difficult to implement.

Alternative 4

Accelerated recognition of loss reduction investments in the rate base is a reasonable alternative. Assuming that the separation of incremental loss reduction investment can be separated from normal investment, this alternative would be the simplest incentive alternative to introduce. It may produce a lower long term risk to the customers of over crediting the loss reduction investment as any rebasing of the assets would capture what is already identified as a real investment in the distribution system, whether motivated by loss reduction or other considerations.

Appendix 1

APPENDIX # 1

Distribution revenue	$464,835.45
Utility kW.h	31,000,000
utility losses kW.h	1,825,900
Utility Losses %	5.890%
a large customer kW.h	4,150,000
large customer losses using factor kW.h	244,435

	price #1 senario 1	price #1 senario 2
Actual % losses of large customer	1.60%	7.50%
Actual losses of large customer kW.h	66,400	311,250
reduction in losses kW.h	- 178,035	66,815
commodity cost	$ 0.0500	$ 0.0500
Difference in losses	-$ 8,901.75	$ 3,340.75
% of distribution revenue	-1.92%	0.72%
% of full MARR	-7.42%	2.78%
FULL MARR	$ 120,000	$ 120,000
% of Shareholders deemed share MARR	-14.84%	5.57%

	price #2 senario 1	price #2 senario 2
Actual % losses of large customer	1.60%	7.50%
Actual losses of large customer kW.h	66,400	311,250
reduction in losses kW.h	- 178,035	66,815
commodity cost	$ 0.0550	$ 0.0550
Difference in losses	-$ 9,791.93	$ 3,674.83
% of distribution revenue	-2.11%	0.79%
% of full MARR	-8.16%	3.06%
FULL MARR	$ 120,000	$ 120,000
% of Shareholders deemed share MARR	-16.32%	6.12%

		price #3 senario 1		price #3 senario 2
Actual % losses of large customer		1.60%		7.50%
Actual losses of large customer kW.h		66,400		311,250
reduction in losses kW.h	-	178,035		66,815
commodity cost	$	0.0600	$	0.0600
Difference in losses	-$	10,682.10	$	4,008.90
% of distribution revenue		-2.30%		0.86%
% of full MARR		-8.90%		3.34%
FULL MARR	$	120,000	$	120,000
% of Shareholders deemed share MARR		-17.80%		6.68%

Appendix 2

APPENDIX # 2

Addition of a 1000 kW merchant generator

	price #1	price #1	price #1
operates % of time	100%	80%	50%
impact on losses	-3%	-3%	-3%
reduction in losses	262,800	210,240	131,400
commodity cost	$ 0.0500	$ 0.0500	$ 0.0500
Difference in losses	$ 13,140.00	$ 10,512.00	$ 6,570.00
% of distribution revenue	2.83%	2.26%	1.41%
% of full MARR	10.95%	8.76%	5.48%
FULL MARR	$ 120,000	$ 120,000	$ 120,000
% of Shareholders deemed share MARR	21.90%	17.52%	10.95%

	price #2	price #2	price #2
operates % of time	100%	80%	50%
impact on losses	-3%	-3%	-3%
reduction in losses	262,800	210,240	131,400
commodity cost	$ 0.0550	$ 0.0550	$ 0.0550
Difference in losses	$ 14,454.00	$ 11,563.20	$ 7,227.00
% of distribution revenue	3.11%	2.49%	1.55%
% of full MARR	12.05%	9.64%	6.02%
FULL MARR	$ 120,000	$ 120,000	$ 120,000
% of Shareholders deemed share MARR	24.09%	19.27%	12.05%

	price #3	price #3	price #3
operates % of time	100%	80%	50%
impact on losses	-3%	-3%	-3%
reduction in losses	262,800	210,240	131,400
commodity cost	$ 0.0600	$ 0.0600	$ 0.0600
Difference in losses	$ 15,768.00	$ 12,614.40	$ 7,884.00
% of distribution revenue	3.39%	2.71%	1.70%
% of full MARR	13.14%	10.51%	6.57%
FULL MARR	$ 120,000	$ 120,000	$ 120,000
% of Shareholders deemed share MARR	26.28%	21.02%	13.14%

CURRICULUM VITAE
of
ROGER WHITE

EDUCATION

- partial MBA McMaster University
- Professional Engineer - 1975
- graduated B.A.Sc. (electrical) University of Windsor - 1972

PROFESSIONAL ASSOCIATIONS

- APEO (Association of Professional Engineers of Ontario)

ONTARIO HYDRO SERVICE (1976 - 1993)

• Head Office: - Superintendent Policy -Municipal & Industrial Service 1988- 1993
-Industrial Service Superintendent (1986-1988)
-Municipal Service Superintendent (1984-1986)
-Rural Service Supervisor (1980-1984)
-Municipal Service Supervisor (1976-1980)
• joined Ontario Hydro as a Consumer Service Supervisor (1973-1976)

EXPERIENCE PRIOR TO ONTARIO HYDRO

• instructor St. Clair Community College (1 year)
• worked 3 years in trade positions for Bell Telephone and Windsor Utilities Commission

MAJOR ACTIVITIES AT ONTARIO HYDRO

- developed service (supply) policy part of our business for municipal utilities, direct customers, rural retail customers and distributing companies over the last 20 years.

- understand both customer needs and sound principles of a customer/supplier business relationship.

- developed and administered contracts recognizing the close relationship between contract terms and rates.

- managed budget and work programs in an environment which often had to respond to conflicting urgent demands.

- negotiated many agreements with utility committees, government agencies, and other stakeholders within and outside Ontario Hydro on such items as rate guidelines (including cost of service studies, wheeling arrangements, communication packages and strategies, etc.

- developed clear policy directives which encourage staff to build business cases and meet customers' needs.

- led teams to develop retail rate design guidelines, computer systems, and emergency power shortage planning.

- supervised customer service and power billing staff.

- provided timely feedback to executives.

- worked with others to facilitate the desired changes of the recent revisions to Ontario Hydro's regulatory criteria including the associated accounting and rate base implications.

- reviewed financial statements and regulated investor owned companies.

1. • provided comments to the Law Division and executives for corporate response from customer service and business perspectives on changes to the Power Corporation Act, Public Utilities Act, and other provincial and federal statutes.
2.
3. • served as an expert witness on cost allocation, wholesale rate design and billing of Ontario Hydro's bulk customers

- acted as primary lead within Ontario Hydro on negotiations with the Municipal Electric Association on the development of the 1994 amendments to the Power Corporation Act (Bill 185).

<u>OUTSIDE AGENCY RESPONSIBILITIES WITH ONTARIO HYDRO</u>

- worked with Ministry of Municipal Affairs staff on legislation
- responded to Ontario Energy Board staff on matters relating to Ontario Hydro regulation on a day to day basis
- worked with Ontario Municipal Board staff and commissioners on matters of overlapping jurisdiction for our agencies
- participated as a member on a number of Municipal Electric Association Committees:
  - Time-of-Use Rate Implementation
  - Service Charge Rate Structure Communication
  - Unregistered easements and land rights from OH
  - Retail Rates and Power Costing
  - Miscellaneous Charge
  - Rate Design Workshop
  - Ad Hoc Committee on Municipal Utility Expansions

EXPERIENCE PROFILE SINCE 1993

President, Energy Cost Management Inc. (ECMI) 1995 - date
Roger White and Associates 1993 - 1995

- developed rate and boundary adjustment workshops and manuals for the Municipal Electric Association
- prepared many boundary adjustment financial feasibility studies and provided guidance and support to consultants related to boundary adjustment issues and acted as an expert witness
- provided presentations to professional associations and clients on government policy papers and statute implications
- designed prepared and implemented reciprocal service agreements between MEUs dealing with staff, equipment and other significant items
- served as an expert witness in arbitration proceedings

Most recent activities include:

- intervened in Ontario Energy Board licencing process for Ontario Hydro Services Company on behalf of clients
- participated in presentations to Association of Municipal Managers, Clerks and Treasurers around the province
- provision of technical support to many municipal utilities and municipalities as they change to accommodate the OBCA companies for their utilities
- prepared merger studies for MEUs under Bill 35
- provided support to Local Distribution Companies (LDC's) in the preparation of initial rate unbundling rate applications
- provided support to LDCs for second tranche and Regulatory Asset Recovery applications
- provided initial support in scoping a regulatory submission for an out of province utility
- provided service to individual end use customers with respect to contracts including terms and conditions of supply
- involved on behalf of ECMI clients in the Service Quality regulation and Cost Allocation

working groups established by the OEB

- served on the three oversight groups and chaired one working group and participated directly in two other working groups of the 2006 EDR Handbook process on behalf of ECMI clients