RP-2004-0188

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15 Sched. B;

AND IN THE MATTER OF the preparation of handbook for electricity distribution rate applications.

Responding Submissions On Behalf Of
Energy Probe Research Foundation

28 February 2005

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Draft 2006 Electricity Distributor Rate Handbook

Introduction

1. Energy Probe's Response Submission does not address all issues. The Submission follows the chapter headings as set out in the draft handbook, with Conservation and Demand Management (C&DM) added at the end.

Chapter 3

3.0 Test Year and Adjustments

1. Energy Probe recommends Alternative 1. We agree with Hydro One that 2006 material event disclosure should only be applicable to applicants filing on a future test year basis.

3.1 Historical Test Year versus Future Test Year

2. If an applicant is filing on a Forward Test Year basis (Option 3) as it was defined in page 17 of the 2006 EDR Handbook, the filing requirements associated with this option should include a forecast of the charge determinant statistics (i.e. KWh/customer and KW/customer).

3.2. Test Year Adjustments

Option 1: Tier 1 Adjustment

3. Energy Probe recommends Alternative2 as set out on p. 18. We agree with Hydro One that "*2006 in-service transformer stations should not be included as a Tier 1 rate base adjustment. Applicants who wish to include 2006 in-service additions should file on a future test year basis*".

4. We support the submission of the School Energy Coalition that "*it is already true that the Tier 1 adjustments approved – all of which relate to 2004 or 2005 - tend to favour rate increases rather than decreases, but the working group sought as much of a balancing of interests as possible. Adding a further adjustment or adjustments for 2006 would skew that balance, and should not be permitted*".

Tier 1 Adjustment: Rate Base 6. (p. 21)

5. We recommend alternative 2. As it was mentioned above, new transformer stations and directly-associated facilities with an in-service date of 2006 should not be included in Tier 1 rate base adjustment, unless applicants file on a future test year basis.

Non-routine/usual Tier 1 Adjustments (p. 21)

6. Energy Probe agrees with Toronto Hydro that Non-routine/unusual Tier Adjustments relative to material non-routine or unusual events that occurred in 2004 may have to be addressed as a factor-Z. However, Energy Probe believes that applicants coming forward with 2006 rate applications including amounts for non-routine or unusual events that occurred in 2004 should provide information on the non-routine events and also on normal conditions so that the incremental expenses can be clearly identified.

Reply to Hydro One Comments on LV Charges

7. In its Final Argument, Hydro One pointed out *" it is expected that the next generation of LV rates to be submitted by Hydro One to the OEB for review and approval will be based on more recent costs and charges and will be on going forward (i.e. 2006) consumption levels of Embedded customers*".

8. Energy Probe recommends that LV cost should be reflected in 2006 rates as regulatory assets. As it was stated in our submission for Final Arguments, Hydro One's LV rates should be reviewed as part of comprehensive cost allocation and rate design review, and we believe that Hydro One's LV rates should not be reviewed in the 2006 EDR proceeding. We understand that the next generation of LV rates cannot be calculated unless a full cost allocation study is undertaken. For these reason, 2006 Hydro One's rates should reflect $25.6-millon LV cost.

9. Because the $25.6-millon LV cost is addressed as a regulatory asset, in the 2006 Rate Application Model the LV cost will not be reflected in the Hydro One's Base Revenue Requirement. However, the $25.6-million is not an extra revenue to be added to capital cost and distribution expenses. For this reason, the $25.6-million should be subtracted from the Hydro One's Base Revenue Requirement. This statement is complementary to the Paragraph 6 of the section Section 8.3, C&DM, Smart Meter, and Regulatory Asset Amortization Revenue Requirement and Chapter 3.2 Test Year Adjustments of Energy Probe's Final Argument.

Option 2: Tier 2 Adjustments (p. 22)

10. According to the 2006 EDR Handbook, the purpose of Tier 2 adjustments is to restore capital investments not made and distribution expenses not incurred due to one or both of the following circumstances:

- the applicant began the 1999 RUD process with negative returns

- the applicant did not receive the second third of the market-adjusted revenue requirement increment.

11. For the Board to approve the Tier 2 adjustment, the applicants should demonstrate it has suffered hardship as a result of one or both of the circumstances outlined. Energy Probe recommends that hardship claims should be limited impacts on the quality of service provided to customers, asset mining, or deferral of needed maintenance not the restoration of foregone profits. We believe that prudently incurred corrective actions, not hardship, should be funded. We believe that compensating applicants for revenues that they did not receive in previous years involves a decision that is out of the scope of this proceeding.

12. The Handbook pointed out that the Tier 2 adjustments are not an entitlement. They represent the amount of distribution expenses and capital expenditures that the applicant believes it was not able to spend because of the above circumstances, but now wishes to spend.

13. Applicants should be required to provide details of the activities that will be undertaken if the incremental spending is approved. Applicants should provide information on the benefits of incremental expenses, in term of the impact on the quality of service to costumers, reversal of asset mining, or restorative maintenance. Applicants should also provide information on how any claimed hardship matters were dealt with prior to the first PBR decision.

14. ECMI pointed out in argument that a regulatory account and a rate rider may be the appropriate mechanism to recover costs for corrective actions. Energy Probe supports this approach.

Chapter 5

Chapter 5.4 Working Capital Allowance

1. Energy Probe recommends Alternative 1, which is the most limited of the proposed adjustment options.

2. There is no evidence that the existing methodology reflects the prudently incurred cost of working capital. For this reason, we do not recommend using the existing methodology as a base to make further adjustments for possible changes in the cost of power and other expenses. Non-controllable expenses, such as storm restoration, should not be reflected in the working capital allowance.

Chapter 10

10.3 Unmetered Scattered Load

1. With respect to cost allocation section and specifically unmetered scattered leads, on Issues Day the Board ruled:

> ***The Board's ruling on this is that, in general, no changes should be made to customer classes before the 2007 cost-allocation study. However, the Board does consider that the anomaly presented by unmetered, scattered loads should be addressed in this process. The differences between utilities are sufficiently significant, and the issues are sufficiently urgent, that the Board will entertain evidence and argument on this issue.***
>
> ***The Board wishes to indicate that it is preferable that the Working Group resolve, or at least narrow, the issues involved in the unmetered, scattered load question. The Board particularly encourages the development of an interim solution from the Working Group, as the matter is likely to be revisited in the 2007 cost-allocation study.***

2. Energy Probe participated in the Cost Allocation Working Group, and supports the consensus achieved in the matter of Unmetered Scattered Load. The compromise achieved in the working group to be reflected in the 2006 EDR Handbook is as follows:

> On an interim basis for 2006, prior to the cost allocation study and rate re-design that will take place in 2007, unmetered scattered load customers will be treated as follows:
>
> 1.) A distributor that currently has unmetered scattered load charges in either of the following two manners will maintain the status quo in its 2006 rate treatment of unmetered scattered loads:
>
> - The monthly service charge to unmetered scattered load customers having multiple unmetered connection points is on a per customer, and not a per connection point, basis, and the level of the charge is equal to, or less than, the General Service <50 kW monthly service charge per customer.
>
> OR

- The distributor has developed and implemented a unique level of monthly service charge(s) payable by unmetered scattered load customers.

> 2.) A distributor that currently bills its unmetered scattered load customers as small commercial or General Service <50 kW by applying the monthly service charge on a per connection point basis, shall set the level of the monthly service charge at 50% of the monthly service charge of the General Service <50 kW rate and continue to apply it on a per connection point basis.
>
> 3.) From a revenue perspective, a distributor shall be kept whole as a result of any rate changes to the monthly service charge for unmetered scattered loads. Any revenue shortfall that may result from this interim measure will be recovered by means of a re-allocation of the revenue shortfall over all classes (or sub-classes or groups), in proportion to the class's (or sub-class's or group's) distribution revenue, and recovered from all the distributor's customers through both the fixed and the variable components of their respective distribution rates. The re-allocation of the revenue shortfall as a result of applying this interim measure are incorporated into the worksheet Rates 1 of the 2006 EDR Model in Appendix D.

Impact Analysis

3. It is noteworthy that the Cost Allocation Working Group did not produce any analysis regarding the economic impact on non-USL customers resulting from adopting the interim solution.

4. However, at the time of the Hearing held on January 18, two parties expressed opinion on the impact analysis. In particular ECMI and Rogers Cable Inc. in the Transcript at Volume 2, paragraphs 158 and 159, expressed:

> MR.O'LEARY: Mr. White, do you have any views as to the potential impact on any affected customers as a result of the Board approving this compromise?
>
> MR. WHITE: We at ECMI did specific analysis on some of our customers. And with the final solution, the worst impact that the encountered was something less than two percentage point—within a particular LDC.

5. On the other hand, also in the Transcript, Volume 2, commencing at paragraph 229:

> MS. ZARNETT: This is on a very estimated basis. What I did was look at 38 utilities for which I had been provided with information about the treatment of unmetered scattered loads. In some of these, they fall into the -- paragraph 1 of the proposal. They already have a specific rate treatment that's different from the general treatment. In those utilities there would be no change. So some of them would have a change, some of them wouldn't.
>
> 230
>
> And what I did was make an estimate of the number of connections and kilowatt-hours of unmetered scattered loads in the utilities for which rates were available, and on that basis computed the dollar change that would result from a 50 percent reduction in the fixed monthly charge.
>
> 231
>
> That was based on actual 2004 rates, and doesn't include anything for changes in the rates in 2005 and 2006, and does not include the fact that some of this money would be reallocated back to unmetered scattered loads themselves.
>
> 232
>
> On that basis, I then looked at the number of customers in the utilities and computed that there would be, overall, about 30 cents a year of impact per customer.
>
> 233
>
> So then, extrapolating that, assuming that the proportions and the relationships are the same for those utilities for which I did not have data, 30 cents a year, based on 4.3 million customers in the province, is about $1.3 million.

Position of School Energy Coalition

6. The School Energy Coalition provided the following recommendation with respect to the cost exposure for remaining non-USL customers in their February 14, 2005 Submission in Paragraphs 252 and 253:

> The consensus was reached on the basis of anecdotal evidence that the impact across the province of this cost re-allocation was minimal. Some evidence indicated that the total reallocation would be less than $1 million, and generally it was agreed that the re-allocation could not exceed $3 or $4 million. This allowed those who would have preferred a proper cost allocation study to support the consensus.

Given the evidence before the Board that the impact is not known with accuracy, it is submitted that the Board should require applicants to which paragraph 2 on page 102 of the Draft Handbook applies to file, with their application, a calculation of the rate impacts of the change to the unmetered scattered load rate. When all applications are in, the Board will be able to confirm that the impact is sufficiently small to justify the interim solution adopted. Conversely, if the impact is very large (e.g. $20 million as opposed to $2 million), the Board can consider at that time, based on empirical data, whether the appropriate rate classes are bearing the appropriate costs for this interim solution.

Approach of Energy Probe

7. To address the Schools contention that the impact is not known with accuracy, Energy Probe undertook additional analysis in the calculation of the economic impact on non-USL customers resulting from the interim USL solution.

Methodology

8. Our analysis of the impacts is based on the following assumptions:

- First, we analysed 37 utilities. We used 2003 PBR data for customer numbers and other input assumptions. These utilities serve about million 3.3 customers in all customer classes, representing about 75% of the total number of customers in Ontario.

  We used 2004 rates for the impact calculations.

  Among the utilities analysed, while some utilities will maintain the Status Quo, others will apply a 50% reduction of the fixed monthly charge to USL customers in 2006. In particular, nine LDCs will maintain the Status Quo. Among them, some LDC charge to USL a unique fixed monthly charge regardless the number of connections they charge, whereas others bill USL customer a specific monthly fixed charge different form the one charge to the general service customers. The latter is the case of Hydro One and Toronto Hydro.

- Second, we estimated the number of USL customers for each utility analysed using data provided by utilities throughout the meetings of the Cost Allocation Working Group. Based on this data, we estimate that USL customers represent about 8.5% of the general service customer class. Taking into account PBR data, the 37 utilities analysed account 310,000 general service customers. Excluding

LDCs that fall in the Status Quo, the 50% reduction of the monthly fixed charge would be applicable to almost 12,000 USL customers.

Energy Probe's Impact Analysis

9. Based on the assumption explained above and the analysis attached, the reduction addressed afford to the 11,000 USL customers by the consensus would represent a change in rates totalling $1.5-million. This amount would be transferred to the approximately 1.3 million remaining non-USL customers. Our impact analysis for individual LDCs indicates that the highest impact does not exceed $3 per customer (See Table 1). As well, the impact on non-USL customers would not exceed 1% of the revenue requirement associated with these customers.

10. Even though the results achieve in our analysis fall in an acceptable impact range, Energy Probe recommends that in considering an interim solution for USL, the Board may wish to take into consideration a cap expressed in $ per customer. Energy Probe suggests that a cap of $3 or $4 per customer seems to be appropriate.

10.6 Distributed Generation

11. In its argument the DG Taskforce urges the Board to "redirect transmission savings to the parties who created these savings. The DG Taskforce claims that its particular the proposal to redirect transmission "savings" arose from consensus. GEC made similar submissions.

12. Energy Probe has been a long standing supporter of DG. For 25 years, Energy Probe has championed the creation of the competitive market in Ontario, in part to promote distributed generation. One of Energy Probe's researchers was on the original board of directors of the Independent Power Producers Society of Ontario. Energy Probe frequently speaks to public audiences on the benefits of DG. However, in the instant case, Energy Probe opposes the proposals of the DG Taskforce and GEC on the grounds

that their proposal would overturn previous Board decisions that limited the subsidization of DG.

13. The consensus claimed by the DG Taskforce seems to be a consensus mostly of LDCs and beneficiaries. Energy Probe is not aware of any consumer groups being represented in the consensus.

14. The DG Taskforce and GEC present submission unsubstantiated by evidence. This is because the matter received scant attention in the EDR 2006 process. Neither the DG Taskforce nor GEC brought any witness to defend their perspective under cross-examination. As a result, the Board has no record in the case to work with in reaching its decision.

15. Fortunately, the Board can draw on a very extensive previous record in this exact matter. The DG Taskforce and GEC asked the Board to throw out the status quo allocation of claimed transmission benefits arising from the Distribution System Code. Neither the DG Taskforce nor GEC make any attempt in their submissions to consider how the impugned elements of the DSC arose. The status quo, which is identified as Alternative 1 in the HB, arose not by random accident but after arduous litigation and considerable consideration from the Board. It would be absurd for the Board to throw out the status quo, as it is invited to do, without carefully considering the reasoning behind the existing rules in the first place.

16. In RP 1999-0044 the Board considered the appropriate rate treatment for transmission charges for DG. In 1998, the Ontario Market Design Committee had recommended gross load billing, that is, calculation of transmission fees on the basis of electrical loads, and not netting loads against self generation. The reasoning behind this recommendation was that since transmission costs are almost entirely sunk, net load billing for customers with self generation would not create real transmission cost savings but would simply transfer the sunk costs from customers with self generation to customers without self generation.

17. With net billing for transmission, the apparent economics of two identical generators, one located inside a customer's fence and another located immediately outside that fence, would appear to be different with the advantage to the inside-the-fence unit. However, the actual costs and benefits to the overall power system of the two generators would be identical. Net billing for transmission encourages uneconomic bypass, a matter historically of great concern to the OEB with respect to gas. With net load billing, if DG grows to a large portion of overall supply, the financial integrity the transmission system could be at risk. The Market Design Committee, in an effort to level the playing field and eliminate damaging cross-subsidies, opted for gross load billing as a principle to guide transmission rate design.

18. "Gross" versus "net" was aggressively litigated at RP 1999-0044. Energy Probe agitated for the "gross" side. GEC and many of the parties that are today members of the DG Taskforce were active in that case, pressing the "net" side. The "net" supporters urged the Board to go "net" for all aspects of the transmission tariff.

19. In the end, the Board endorsed some of the arguments of both the "net" and the "gross" sides, splitting the transmission tariff roughly in half. Network transmission service would be billed on the gross basis and connection would be billed on a net basis.

20. Immediately after releasing the RP 1999-0044 Decision with Reasons, the Board also released the Distribution System Code, containing the rules that the DG Taskforce is now seeking to repeal.

21. With respect to the treatment of DG, RP 1999-0044 and the DSC are of a piece, part of one single overall treatment of the related issues of benefit allocation, investment promotion, and protection of non-participating customers.

22. Government policy toward DG, which GEC and DG Taskforce quotes at some length in their submissions, are not significantly different now than they were when the

RP 1999-0044 decision was rendered and the DSC released. If anything, the current government's endorsement of DG is fulsome than the policies of recent previous governments.

23. In the recent past, government policy toward DG was not just fulsome but aggressively supportive. In May 2000, sixteen days before the OEB released its RP 1999-0044 decision on the contested matters of transmission cost allocation and rate design, Energy Minister Jim Wilson made a key note address at a major conference, Gas and Power Fair 2000, attended by several members of the OEB announcing his opposition to a rate approach that would recover historic costs from all customers on the basis of the total electricity consumed. In the speech, he said "I've listened to concerns that gross load billing would make most self-generation projects uneconomic" and that this was an outcome "we want to avoid". He went on, "The issue is currently before the Ontario Energy Board, and I'm confident that the OEB, as our independent regulator, will come up with a decision that protects the best interests of customers and advances competition."

24. The path recommended by the DG Taskforce and GEC is the path of capricious regulation. They would have the Board throw out the results of a complex set of decisions that balance competing perspectives based on nothing more than a consensus of a group that appears to be largely representing LDCs and direct beneficiaries. The Board is unlikely to reach a durable reform of the existing system based on nothing more than a tapestry woven from the submissions for lawyers unsubstantiated by any evidence. The failure of the DG Taskforce and GEC to present a witness leaves the Board with no evidential base upon which to commence a serious review of previous Board decisions and policies.

25. There are a host of policy options available to encourage much need distributed generation in Ontario, such as locational marginal energy pricing that captures the actual

value of transmission congestion, but second-best subsidization of DG by uneconomic bypass that transfers fixed transmission charges to third parties is not the way to go.

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Chapter 14: Comparators and Cohorts

1. Many of the stakeholders commented on common issues. The following chart summarizes the responses of the stakeholders on whether benchmarking should be used for screening in 2006, whether benchmarking should be used beyond 2006, and whether benchmarking data and analysis should be disclosed publicly.

Benchmarking Issue Analysis

Stakeholder	Screening for 2006?	Benchmarking beyond 2006?	Public Data Disclosure?
VECC	Yes	yes	yes
AMPCO	Yes	yes	
CCC	Yes	yes	yes
Energy Probe	Yes	yes	yes
LPMA			yes
CME			yes
Schools	Use rate screen		
Hydro Ottawa	ambiguous		no
Powerstream	Yes		disclose to intervenors only
Toronto Hydro			no
Niagara Erie	No	yes	no
Hydro One	Yes but not for HONI	yes	
EDA			no
ECMI	No		disclose to intervenors only
Union Gas			no
PWU	only if SQI included		

2. Some stakeholders provided more unique comments on particular issues or views on issues beyond the three summarized above. These are summarized as follows:

AMPCO

- include interjurisdictional comparisons
- supports Camfield's methodology and Ex. 6.3 filing requirements

ECMI

- ECMI claims that the Board decided in the Issues Day part of the process that comparators and cohorts will be used as a screening tool "for Board staff only". Energy Probe reviewed the Issues Day decision and do not find any evidence to support this claim.
- benchmarking capital will not be possible for 2006
- several concerns with cohorts, number of cohorts are arbitrary, HONI and TH should not be excluded

HONI

- claims that Camfield agreed to exclude HONI (failed to note ECMI cross examination of Camfield on this issue and Camfield's admission that the exclusion of HONI was made a priori)
- recommend work on data consistency and accuracy first before benchmarking

Ottawa

- Data consistency concerns
- ambiguous comments suggesting that the only purpose of C&C work is to reduce data inconsistencies but on the other hand endorse the use of C&C for screening
- "once the screening is completed, the comparator information should no longer be of relevance to the review, and should not be used to question any aspect of the application"
- recommend confidentiality of comparator information on the grounds that comparators are experimental

Toronto Hydro

- several general complaints against benchmarking
- prefers analysis focused on cost per customer
- says large utilities will be subject to scrutiny irrespective of screening results

Powerstream

- wants to know if it is an outlier before making its application

3. No comments on benchmarking from the following stakeholders: PP, ESA, Woodstock, Coalition of Issue 3 Distributors, Brantford, Veridian, London, Greater Sudbury, EGD, GEC.

4. Conclusion: Energy Probe suggests that there is enthusiastic support from customers for benchmarking, and often grudging recognition that benchmarking is inevitable from utilities and related interests.

5. There is also a widespread recognition that effective benchmarking for 2006 will require significant effort. Energy Probe suggests that a public process be developed by the Board with a mandate to develop benchmarking tools for application to 2006 rates and beyond.

Conservation and Demand Management

1. Energy Probe will present its Responding Submissions on C&DM in response to the submissions made by other parties on the five key decision points that Board Staff requested comment on.

2. The five key decisions points identified by Board Staff in their submissions, Transcript Volume 11, commencing at paragraph 1034, were:

- Revenue Protection
- Shareholder Incentive
- Level of C&DM Spending
- Regulatory Treatment of Spending
- Loss Factor Incentives

3. Board Staff noted in their submissions at paragraph 1047, that Mr. A.J. Goulding, the expert witness called by Board Staff, in his report, set out six criteria that might be used to evaluate any models put forward for regulating C&DM:

- Administrative Simplicity
- Bill Impact
- Regulatory Consistency
- Incentives Compatibility
- Financial Stability
- Universality

Revenue Protection

4. In the Submissions of the Green Energy Coalition (GEC), February 14, 2005, Mr. Poch argues on Page 11, in response to ***Alternatives to LRAM - Woodstock's proposal***, that:

> The proposal to move to a 100% fixed charge for distribution costs would reduce the conservation price signal to consumers (see Goulding at v.9, p. 141-142) and should be rejected on that ground alone.

5. While the reference is incorrect as to its location (should be Goulding at v.9, p.161-162), it also appears to be incorrect in its interpretation. To clarify, we quote from the transcript:

> 159
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> MR. GOULDING: However, as a regulatory economist, I am a great believer in getting prices right and in providing appropriate price signals. I think one of the challenges for small customers, and one which -- and I want to add that this is outside of the 2006 box in which our evidence is placed, but that, you know, as we see an evolution towards realtime meters and realtime pricing, **the conservation incentive is going to come from an exposure to some measure of commodity price volatility**. And I believe that that's appropriate. (emphasis added)
>
> 160
>
> I understand that, in the current rate-making structure, and given the structure of default and supply, that there **may be an argument that moving to flat-rate pricing changes the incentives to conserve on the customer**. But what we want to be doing, I believe, is sending the appropriate price signals to customers, and I believe that -- well, let me step back. It's not my role to make any particular recommendation regarding any of the four models, and I shouldn't go beyond that. (emphasis added)
>
> 161
>
> MR. POCH: All right. But you acknowledge that there's a trade-off here that this **may diminish the conservation price signal to the end-use customer**. There may be other reasons you want to do it, but, looking at that slice of the picture, there would be a trade-off there. (emphasis added)
>
> 162
>
> MR. GOULDING: I think that's fair.

6. An affirmative “I think that's fair” reply to a cross examination proposal that there is a trade-off that **may** diminish the conservation price signal to the customer is absolutely not support for indicating that Mr. Goulding’s expert evidence is that it **would** reduce the conservation signal to the end-use customer. Especially since, in response to a question from Mr. Poch, Mr. Goulding had just finished stating that as a regulatory economist, he felt that the conservation incentive is going to come from an exposure to some measure of **commodity** price volatility.

7. In the Submissions of the Green Energy Coalition (GEC), February 14, 2005, Mr. Poch further argues on Page 11, in response to ***Alternatives to LRAM - Woodstock’s proposal***, that:

> Mr. Chernick noted in his written and oral evidence that the proposal of a 100% fixed charge for distribution costs is contrary to cost causation, does not address the problem of lost revenues, and does not reduce complexity (v. 9, p. 889 *et seq*.)

8. Energy Probe wishes to point out that in addition to Woodstock Hydro’s proposal for a 100% fixed charge for distribution costs, the Electricity Distributors Association in its Submission of February 14, 2005, on the Rate Handbook at pages 41 and 42 stated:

> The EDA supports the “pays as you go” approach advocated by the most of the experts but would suggest that consideration be given to the longer term goal of moving to “flat rate pricing and customer bill savings” approach in the future.
>
> Mr. Goulding noted that it would be more economically efficient to have a fixed charge for distribution services (Tr. Vol. 9 Para. 538) and fixed charge more accurately represents distribution systems (Tr. Vol. 9 para. 539). A flat charge would allow a less administratively complex regulatory framework for CDM (Tr. Vol. 9 para. 567) and would create financial stability for distributors (Tr. Vol. 9 para. 570).

9. In the Submissions of the Green Energy Coalition (GEC), February 14, 2005, Mr. Poch further argues in respect to cost causality on Page 11, in response to ***Alternatives to LRAM - Woodstock's proposal***, that:

> A 100% fixed charge is contrary to cost causality because long run marginal distribution costs rise with kWs and kWhs delivered. This relationship between kWs and kWhrs and long term capital investment requirements was confirmed by Mr. Goulding at v. 9, p. 165-170.

10. The Electricity Distributors Association in its Submission of February 14, 2005, on the Rate Handbook at page 42 stated:

> Chernick's description of the problems with fixed charges (Tr. Vol. 10 paras. 580-583) demonstrates a misunderstanding of the proposal being developed by Woodstock Hydro. Mr. Chernick assumes customers would move in and out of subclasses based on their consumption changes. In fact the fixed charge would be based on the physical characteristics of the connection to the customer that changes only on certain occasions for certain customers.
>
> A move towards fixed charges would ensure distributors are not adversely affected by reduced energy consumption regardless of who promotes conservation initiatives.

11. Both Mr. Goulding and Mr. Chernick demonstrated a misunderstanding of the Woodstock Hydro proposal for a 100% fixed charge for distribution costs. In Mr. Goulding's case, one of the four regulatory models that he brought forward called for a fixed charge for distribution, but the Woodstock Hydro proposal is not identical to Mr. Goulding's Model 4. The EDA certainly has a fuller grasp of that proposal, hence its support.

12. To argue as Mr. Poch appears inclined to do, that the 100% fixed charge for distribution costs proposal to set rates annually is contrary to cost causality because long run distribution costs rise at the margin with respect to kWs and kWhs delivered, is to be obtuse, at best. To use Mr. Goulding's responses to cross examination as quoted (Trans. V.9, pps 165-170) as support for opposing the Woodstock Hydro proposal, is to misconstrue his expert testimony:

> MR. POCH: Okay. And I understand the point you've made that, in the short term, a distribution utility's costs are fairly fixed; is that right? 163
>
> MR. GOULDING: Yes. 164
>
> MR. POCH: You would agree, I think you've agreed in your evidence, where you say, and I'm reading from page 34: 165
>
> "These additional costs do not arise as a result of hour-by-hour changes in load on the distribution system, but rather are due to load growth over time." 166
>
> I take it from that and from experience, you would agree that, over a long-time horizon, there is some correlation between the kilowatts and kilowatt-hours on a distribution system and the need to expand that system. 167
>
> MR. GOULDING: Yes. I -- the costs, you know, the capital costs tend to have a, sort of, step change to them with regard to building out the distribution system. But in terms of designing an incentive for the conservation of energy, I would like -- I would prefer to think about ways of incentivizing the utility in its long-run system planning, to go through a least-cost process to handle that. 168
>
> MR. POCH: These aren't mutually exclusive, though. 169
>
> MR. GOULDING: No, certainly not. 170

13. In summary on these points, Mr. Poch, and some other parties in their written submissions, make much of the supposition that to a 100% fixed charge for distribution costs would reduce the conservation price signal to consumers. There is no evidence in the 2006 EDR process to support that presumption.

14. The argument on this point is often made that because the amount left in the variable rate once all distribution charges are moved to the fixed charge, that is the commodity cost, is now a penny or so less per kW, that customers will not be moved to conserve – better to have an LRAM to recapture the lost distribution charge, because by the time customers pay for the LRAM they will have forgotten where it came from. This argument assumes that customers never figure it out, and will be motivated to conserve by false signals.

Shareholder Incentive

15. In the course of the 2006 EDR process, a number of the LDCs and some intervenors have supported the February 14, 2005 written submissions of Hydro One with respect to Conservation and Demand Management. In particular, the submission quoted from pages 21 and 24 of that submission:

> **Incentives to Shift Scarce Resources to CDM from Other Activities**
> Hydro One agrees with evidence submitted by all of the above parties, which recognizes the need for incentives to encourage utilities to assign their limited resources from more traditional utility operations to CDM activities.

16. Hydro One is recommending that ratepayers should fund "Incentives to Shift Scarce Resources to CDM from Other Activities". What is that? Incentives to encourage LDCs to shift their scarce resources from their traditional operations – could that mean ratepayers should pay incentives to encourage LDCs to shift money from maintenance activities, transmission security activities, managerial activities, customer service activities? Would this type of submission be made in any other forum than CDM or DSM? Energy Probe trusts that it would not.

17. The Hydro One Submission appears to presuppose that the traditional operations of the LDCs have become less important to undertake. Or, in the alternative, that there is sufficient fat in the operations budgets which could be safely shifted to CDM.

18. The Ontario Energy Board is directed by Section 1 of the *Ontario Energy Board Act* to be guided by the following objectives:

> 1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service;
> 2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

19. Creating an incentive to shift resources from the traditional activities of LDCs would appear to be in contravention of those objectives. The Board should make it clear in its decision on the manner in which CDM will be regulated to stipulate that the CDM initiatives required of the LDCs in no way lessen their responsibility for traditional operations.

20. The expert witness called by the GEC, Mr. Chernick, summarized the rationale for offering an incentive to the LDCs in the appendix to his evidence:

> DSM must compete for management attention, talented staff, and other scarce resources with other activities, including many that increase sales, reduce costs, or otherwise increase profitability between rate cases. If DSM is simply earning-neutral, management will quite sensibly direct their efforts to those activities that can increase profits.

21. His rationale demonstrates a misunderstanding of the manner in which LDCs in Ontario increase profitability. Increasing sales is not a profit driver.

22. A number of parties to the 2006 EDR process are requesting that the Board continue the 5% SSM that the Board agreed for 2005. Quoting from the February 14,

2005 Submission of Pollution Probe at Page 4, under the heading ***Continuation of the 2005 SSM:***

> In its landmark December 7, 2004 RP-2004-0203 decision the OEB permitted Ontario's electric utilities to apply for a SSM incentive equal to 5% of the Total Resource Cost Test net savings created by their fiscal 2005 "customer side of the meter" CDM programmes. That is, if a utility's fiscal 2005 CDM programmes reduce its customers' bills by $100 million, the utility receives a $5 million conservation profit bonus.

23. It was the recollection of Energy Probe that the Board Panel on December 7, 2004, was careful not to position its decision as landmark. To quote from Volume 1, paragraphs 23 and 24:

> **With respect to incentive plans, or SSM as it's described, the Board proposes to adopt the plan put forward by Pollution Probe. The 5 percent figure appears to be reasonable in the circumstances. There is also some precedent for it. In any event, it can be adjusted by the 2006 EDR panel if necessary on the basis of the fuller record that will be available to that panel.**
>
> **A couple of points of clarification with respect to these two matters. The first is, as was agreed to by the parties, this is voluntary. Each utility will be expected to bring an application. Of course the Board welcomes group applications, as is evident here today. The Board welcomes this initiative. It's obviously in everyone's interest to minimize the regulatory burden. To the extent that applicants can form groups as they are today, that's very helpful.**

24. The 5% appeared to be reasonable in the circumstances but the 2006 EDR panel could make changes if necessary based on a fuller record. It is Energy Probe's submission that while a 5% SSM may be reasonable on a voluntary basis for 2005, where the LDCs are just starting to be involved in CDM, it is not reasonable for 2006 on a mandatory basis.

25. The proposed simple initial SSM of "5% of total TRC (net) savings" is very crude, and over-incents "first savings" and poor and disappointing results. It has also already prompted "me-too" action by the GAS LDCs who like this design better than

Enbridge Gas Distribution Inc.'s (EGDI) more sophisticated and less generous SSM design.

26. It is the responding submission of Energy Probe that LDCs should receive an incentive or a bonus for performing its CDM activities especially effectively. That bonus could reasonably disappear for lacklustre performance, and might even go negative as a penalty for disappointing performance.

27. Energy Probe submits that the Board should avoid the problem which has arisen with the SSM for EGDI, by trying to design an SSM that pretends to be a pure incentive mechanism but really comes very close to guaranteeing EGDI a shareholder profit for performing DSM activities.

28. The Written Submissions of SEC on February 14, 2004 outlined a very credible approach for regulating C&DM. The sections, staring at Page 73, paragraph 340, to deal with SSM are most impressive and present a rational method for incenting the C&DM performance of LDCs. The SEC wishes to avoid the Insipid Results SSM (IR-SSM) – a 5% SSM payment starting at the first dollar of TRC. To quote from that paragraph:

> … Yet the proposal put forth by Pollution Probe, and reluctantly supported by Mr. Chernik, rewards exactly that. Under that proposal – a 5% SSM from the first dollar – each distributor gets a budget of ratepayers' money to spend on C&DM, and if any net TRC benefits are generated from that spending (how could there not be?), the distributor is rewarded. It is submitted that this incentive structure sends the wrong message, and wastes ratepayer money rewarding performance that does not require incentives.

29. Energy Probe supports those submissions of SEC. The solution for a credible and cost efficient SSM put forward by SEC avoids guaranteeing the LDCs a shareholder profit for performing DSM activities. It is an incentive for outstanding performance.

30. The SSM model that Energy Probe has supported in the past would reward performance above a target level. In the current environment, this may not be easily applied to the LDCs, and perhaps too much effort would be directed towards setting targets. As Mr. Poch points out at Page 16 of the GEC Submissions, benchmarks are not currently available:

> Mr. Shepherd, in his cross examination asked whether an incentive that rewards above average performance rather than "insipid" performance would be better. All the witnesses agreed that it would be appropriate in future years (once benchmarks are available) to reconsider the SSM design to increase rewards for higher performance and reduce rewards for below average or insipid performance. The approach would involve a review of experience and a scaling formula since the effort required to individually set 90 targets would be prohibitive. The problem is that no such benchmarks are currently available. It is possible to devise an SSM that bases reward on relative performance (ie. how the LDC performs relative to the group) in advance, but there is a serious problem with any such proposal. If the Board values information sharing and cooperation among the LDCs, an incentive that rewards the top performers only will be an incentive to avoid sharing information with other utilities.

31. Energy Probe submits that Mr. Poch's concern that a benchmarking approach would restrict information sharing between LDCs is not reason enough to reject this approach. Evidence in the Review of Regulatory Assets proceedings confirmed that LDCs are not prone to sharing best practices in any event.

32. Energy Probe thus supports the SEC regulatory model – benchmarking the positive results of LDC C&DM initiatives against each other's performance until other current benchmarks are established.

Level of C&DM Spending

33. There were no February 14th submissions which provided a pressing need for the Board to set either a cap on C&DM spending or a requirement for spending. Pollution Probe opined in its submission:

> Therefore a high-level of utility spending on CDM is in the economic self-interest of all electricity consumers as long as the spending is cost-effective. According to Mr. Chernick, the Green Energy Coalition's expert witness, the electric utilities should be permitted to spend up to $2.50 per mWh on CDM without seeking individual approval from the OEB.

34. The problem is always to establish cost-effective spending. Those utilities that feel that they can proceed with cost-effective programs beyond the 3rd tranche of MARR spending should be encouraged, but not required, to bring forward a C&DM application for 2006.

Regulatory Treatment of Spending & Loss Factor Incentives

35. Energy Probe repeats and relies on its Written Submission on these key decisions points.

Costs

1. Energy Probe Research Foundation requested its reasonably incurred costs in its Written Submission of February 14, 2005.

2. Now that Bill 100 has now been passed, allowing the awarding of costs in policy processes as well as proceedings, Energy Probe wishes to support the February 14th submission of SEC at Paragraph 363 that:

> …it is appropriate for the Board to exercise its newly-broadened powers to award costs, and to respond to the contribution of the intervenor groups, including the School Energy Coalition, by ordering the recovery by them of their reasonably incurred costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

February 28, 2005

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