RP-2004-0188

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 a handbook for electricity distribution rate applications

Submissions of the Green Energy Coalition:

David Suzuki Foundation
Energy Action Council of Toronto (ENERACT)
Greenpeace Canada
Sierra Club of Canada

GEC has been represented on the Rate Design working group and its counsel chaired the Conservation and Demand Management Working Group. GEC's participation and its submissions will focus on Rate Handbook items that have particular impact on renewable generation and energy efficiency, specifically: Distributed Generation, Standby Charges and C&DM.

10.6 Distributed Generation

Two alternatives have been proposed for crediting LDC embedded generators (that are not LDC customer embedded) with avoided transmission costs. As set out below, GEC supports alternative 2a, which gives a full rather than partial credit to generators.

A. Transmission charges and the RP-1999-0044 decision:

The Board's RP-1999-0044 decision deals with transmission rates and gives the benefit of net load billing to transmission customers for network charges (and for connection charges for existing and new small generators). The 'customers' of concern in that decision were transmission customers being direct transmission customers and LDCs. The Board did not give direction on how the transmission charge savings credited to the LDCs were to be shared among distribution customers. Accordingly, while the Board has been made aware of concerns on this matter before, this is the first occasion in a hearing process where the Board will hear argument on the issue.

It is important to note that the transmission decision does settle the overarching policy question -- should reduced reliance on the transmission system due to embedded generation be recognized in rate making? The answer was yes, an answer that is consistent with recent government policy announcements favouring dispersed generation such as the net billing regulation.

B. The rationale for a transmission credit for generators embedded within distribution areas:

1. Proper economic signals:

At present there is no advantage to a potential generator to locate inside a distribution area despite the likelihood of considerable advantage to the system of such a choice.

While load customers with on-site embedded generation enjoy transmission charge savings to the extent they utilize power on-site, there is no opportunity for non-customer-embedded distributed generation (DG) to reap such a benefit, despite comparable impact on the transmission grid and system overall.

Indeed, distributed generation, whether behind a retail meter or not, benefits all system users by reducing demand on the transmission system. So long as DG does not exceed the local load, it will result in net unloading of transmission. Further, in large load centres (where more DG would be expected to arise) it is conceivable that generation that greatly exceeds its LDC host’s load could still benefit all transmission users by serving nearby distribution areas from ‘the right side' of existing transmission constraints.

It has been suggested by some that reduced reliance on transmission (or distribution) is not a benefit because 'the costs are fixed'. This is a fallacy in both the short and long term. In the short term, reduced transmission loading reduces losses which are a cost borne by all. In the context of the discussion of C&DM loss reduction the Panel heard how losses go up with the square of the current, therefore marginal loss reduction at any time is worth far more than the average loss factor would suggest. Further, reduced transmission use at peak times (when the square factor is amplified by the high loads on the system) is of even greater value.

In the long term, the transmission system is built to meet demand and DG reduces transmission demand. While a limited potential to serve loads must be maintained to accommodate DG outages, if DG is encouraged such that several generators exist in most regions, diversity will ensure that most of the benefit due to reduced transmission need is in fact obtained. The irony is that the 'floodgates' argument works in favour of DG as more DG means less chance that a significant proportion would require backup transmission availability at any given time. Policies that support diversity of DG technology will further enhance this resiliency.

2. Support for government policy:

The timing of this proposed change is particularly well suited to supporting government policy and action favouring Distributed Generation.

In his April 15, 2004 speech to the Empire Club, Energy Minister Dwight Duncan acknowledged the potential for distributed generation projects:

> "Distributed generation, which is also attractive from a security perspective, holds significant promise for the environment, as it suggests an electricity system that minimizes massive transmission networks, and focuses resources only where they are absolutely necessary. Our desire

> is to help Ontarians unlock the potential for efficient electricity generation that is around them, and *we will remove barriers, free up resources and bring new thinking and new ideas to the challenges that lie before us*." (Emphasis added)

Government policy recognizes that DG has numerous benefits for the public. Distributed Generation will:

- help balance supply and demand in light of the promised coal phase out and the poor performance of nuclear generation
- displace coal-fired power (from Nanticoke or from imports) and thus greatly reduce adverse environmental and public health impacts
- add fuel and geographic diversity to the electricity grid and thereby enhance system security
- reduce system losses with corresponding generation and transmission savings
- reduce commodity costs by enhancing capacity available at peak times

3. The status quo skews siting decisions for renewable power and reduces fairness as between single ownership and community based ownership:

At present, customer-embedded (load displacing) generation enjoys the benefit of its reduced reliance on the transmission system. However, the members of a coop who own a community power project such as a wind turbine and who reside in the same region or LDC franchise area cannot obtain the benefit of reduced transmission charges (unless they find a willing host), despite the impact on the transmission system being identical to that of a load displacing generator. The transmission credit would allow the benefits to be distributed to the member owners. As the Board will be aware, this example comes from the real life experience of the Windshare (TREC) project in Toronto. That organization has faced financial pressure to limit its site search to situations where a host is available on-site or face added transmission charges. Such a limitation reduces opportunities for small community based or joint generation projects. There is widespread interest in the agricultural community in joint energy projects such as wind turbines and anaerobic digestion that would not necessarily be able to find a host that could absorb the full output of the project on-site. A fair credit mechanism would provide a truer economic signal and optimal siting could be found that maximizes societal benefits.

4. Concerns about large generators locating poorly are not well founded:

Some have argued that a transmission credit would induce large generators that should tie directly to the transmission system to choose a societally less optimal site within an LDC and connect through the distribution system. In fact, the limited availability of high voltage connections inside LDCs will rule out very large generation proposals that could better locate on the transmission system. If a large generator chose to do so they would face costs due to sub-optimal voltage connection or high costs of connection upgrades. If this is viewed as a risk, a further limit on the availability of the credit to situations where the sum of local embedded generation does not exceed the local load would answer the concern.

5. 50% sharing is not appropriate since the impact on other customers is positive:

The alternative proposal of a 50% sharing of the credit between the DG and LDC customers is not founded on economic logic. It is the generator who is avoiding transmission by its choice of location and it is the economics of that choice that the policy is intended to influence. There is no real harm to other customers as there is unlikely to be any significant shift in costs since new generation would lower the LDC's transmission bill in an amount equal to the credit. It is only in the case of existing embedded non-load displacing generation that the current cross-subsidy to LDC customers would be removed. There is no evidence to suggest that these situations are prevalent in Ontario such that rate impacts would be unacceptable. It is appropriate to extend the credit to these generators as it will help ensure they are in a position to continue to generate.

Accordingly, for the same reasons that the government supports DG, (enhanced supply/demand balance, less environmental and public health cost, lower commodity costs, lower long run transmission costs, lower loss costs) all other customers will benefit from policies that encourage DG and have no claim to a portion of the credit.

C. Administration Charge:

Finally, we note that item 10.6(7) of the draft handbook refers to an administrative charge based on a separate cost-justification filing. We have suggested that the choice to levy such a charge be optional as an LDC may view the regulatory and administrative costs of gaining approval for and levying such a charge as inappropriate where there is very little revenue involved. For example, a small utility with a high school solar demonstration project as its only load displacing embedded generator would find the burden of developing, applying for approval and administering the charge out of proportion. Similarly, a large utility may find the administration of the charge a wasteful effort for very small generators. Accordingly, we favour version 2d or suggest that the Board phrase the section “Where a distributor chooses to levy an administration charge it shall apply...”

10.7 Standby Charges:

The draft EDR Handbook allows Distribution utilities to levy standby charges to load displacing generation to cover the costs of holding capacity available to serve load when the generation is down. In any month where power is taken from the grid due to an embedded generation outage the standby charge is suspended and the usual demand charges are paid. For large generators the standby charge may be a reasonable charge as the LDC's need to be able to serve the related load and may have associated investment and operating costs that would not be recouped in occasional monthly demand charges. However for small generators it is likely unsupported by the facts and unduly administratively expensive and burdensome.

Upstream wires and transformers serving loads with small amounts of load displacing generation are unlikely to be sized differently if the generation is small relative to the load in that part of the distribution system. Distribution system operation is unlikely to be significantly impacted by the presence of small load displacing generators. For renewable generators the likelihood is that they will be intermittent and will almost always be paying demand charges, so the standby charge becomes nothing more than an administrative burden and cost as it is routinely suspended.

Accordingly, GEC suggests that up to 2 MW should be exempted from standby charges. This threshold is consistent with the Board's position on a suitable gross vs net billing threshold (that grew out of the RP-1999-0044 decision based on administrative simplicity). The exemption would relieve both the generator and the LDCs of the administrative burden for billing small generators. This would also ensure no conflict with the net billing policy that the government has recently announced and would be consistent with the concerns expressed in paragraph 3.4.11 in the RP-1999-0044 decision in regard to avoiding hefty fixed charges for small customers.

Finally, if the Board is persuaded that a standby charge for smaller generation may be appropriate, we suggest that the current process has not allowed an opportunity for intervenors to investigate the details or basis for such a charge and the matter would be better considered as part of the cost allocation process.

10.10 C&DM

A. Introduction:

The Ontario government has committed to creating a conservation culture, reducing energy use by 5% by 2007 and the phase out of coal-fired generation.

In his April 15, 2004 speech to the Empire Club, Minister Duncan emphasized that Ontario's electric utilities will play a key role in promoting energy conservation:

> "Our sector reforms would also support conservation at the local level. The Ontario Energy Board would also establish a framework to help local distribution utilities deliver energy conservation programs as appropriate. The current disincentives for local distribution companies would be removed, and LDC's would benefit from empowering their customers to conserve electricity and making their own systems more efficient.
>
> We believe that LDCs can and should be agents of change at the local level to promote conservation. LDCs are extremely well placed to encourage conservation and energy efficiency in the communities they serve, and we will need all their expertise, ingenuity and leadership to help build that conservation culture in Ontario." (Excerpted in Ex. C.3 at p. 2)

Government policy clearly supports an enhancement of regulatory mechanisms to encourage LDC C&DM. The Board has already responded to the "third tranche" C&DM directive but was confined by the timing and limits of the directive. For 2006 and beyond the Board is in a position to consider a broader range of requirements and mechanisms to refine and enhance C&DM in Ontario's electricity sector.

While the information base and institutional context will continue to evolve, GEC submits that the Board cannot afford to delay its decisions on these mechanisms. The government's conservation goals are pressing and they are based on a realistic assessment of the societal costs of the generation alternatives. Those that urge watered down efforts, prolonged discussions, and delayed implementation ignore these real costs. As the Ontario Medical Association has noted, over 1800 Ontarians a year are dying pre-maturely from poor air quality.

The recommendations GEC makes below are consistent with the Board's decisions thus far, with government policy, and with the evolution of the Conservation Bureau. Public statements by the newly appointed OPA director confirm a major role for the LDCs. (Eg.: http://www.cbc.ca/ottawa/media/audio/ontariotoday/11a.ram)

The GEC supports lost revenue protection to remove the disincentive to conservation, a shareholder incentive to encourage aggressive and cost-effective efficiency programs, an expense variance account to enable utilities to pursue successful programs and to return to customers any unspent funds, and a streamlined process that reduces regulatory burden and costs, provides accountability, and enhances program effectiveness.

B. Lost Revenue Protection (LRAM):

The evidence of all the witnesses supports the need for some form of lost revenue protection to remove the disincentive that prospective rate making creates for utility efforts to support customer-side conservation. (See Chernick, Ex. C.2, p. 10, Goulding, Ex. C.1, p. 50)

Prospective or retrospective LRAM:

In Ontario's gas sector both prospective and retrospective LRAMs have been used. Union initially used a retrospective LRAM (i.e. there was with no forecast of DSM impacts in the load forecast) and subsequently adopted the approach Enbridge utilizes where the load forecast includes a forecast of DSM impact and the LRAM adjusts only for the variance from forecast. The latter approach better matches rate impacts with benefits however many LDCs may not be in a position to forecast LDC program driven customer conservation impacts for 2006.

To minimize burden on the LDCs, the GEC supports the approach set out in the CWG report and elaborated upon by Mr. Gibbons which allows either approach in 2006. For subsequent periods, GEC submits that LDCs should apply for rates that are adjusted for anticipated C&DM program customer side impacts and the LRAM would then address variances from forecast only, providing a better matching and less retroactivity.

For 2005, where rates were set without inclusion of a C&DM impact forecast, the LRAM will of necessity have to capture the full customer conservation impact.

Alternatives to LRAM - Woodstock's proposal:

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.

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*.)

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.

The alternative does not adequately address lost revenues because the utility would still face jeopardy as customers in a given use category conserve and move to a lower use category (See Chernick at V.10, p. 580). Woodstock acknowledges that fairness would require customer classes to be sub-divided into sub-classes by level of use or small customers would be cross-subsidizing large users (See D9.1, para 31). If there are few such sub-categories, the unfairness would remain. If there are many categories the number of customers migrating from one category to another during the rate period due to conservation would be increased. In both cases, since every customer that moves from one category to another lowers the utility's revenue on every kWh that customer uses, lost revenues would still be significant.

The complexity of the proposal is also significant. Both the initial design of sub-categories and the management of billing and operations with numerous sub-classes would be complex. In contrast, if an LDC is filing for an SSM it is already gathering most of the data needed to clear an LRAM and the added complexity of an LRAM is minimal.

The rate impact of the fixed charge proposal outlined in Woodstock Hydro's evidence appears to have smaller users pay more and larger users pay less which likely penalizes the poor and efficient and rewards the rich and profligate.

Finally, the proposal is contrary to the government's smart metering initiative which seeks to enhance the conservation price signal not diminish it.

Alternatives to LRAM -- increased SSM:

Mr. Goulding offered an alternative in which the SSM sharing ratio is increased such that it offsets lost revenues. He agreed that this approach would increase utility risk -- something that the Chairman has observed that LDC's find a real obstacle to engaging in conservation spending. This approach would also require that the SSM reward every kW and kWh saved and preclude a move to a threshold based SSM in subsequent years. Accordingly, GEC opposes this approach.

Implementation considerations:

As discussed below under ‘G. Streamlining the Process’, pre-approval of screening inputs by a centralized process will ease regulatory burden and reduce regulatory risk.

C. Shareholder Incentives (SSM)

The GEC strongly supports the continuation of the 5% SSM which the Board adopted for 2005 which should also apply to capitalized customer side program expenditures if capitalization is determined appropriate. While it is entirely likely that a refined mechanism will be more suitable in the future, the 5% mechanism is low risk, simple, practical, widely supported, and no viable and preferable alternative has been presented.

The need for incentives:

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.

While Mr. Warren, acting for the Consumers Council and AMPCO seemed to make much of the fact that Mr. Goulding had not surveyed utilities to evaluate the need for an incentive, it should be noted that no challenge was made to Mr. Chernick's enunciation of the factors that create the need for an incentive or his support for the mechanism given his widespread experience in numerous jurisdictions.

During the course of the oral evidence the Chair asked: is mandating C&DM sufficient? Three responses emerged.

First, for the reasons captured above and discussed at length in Mr. Chernick's Appendix A, mandating is likely insufficient given the history and competing pressures on LDC managers.

Mr. Warren put the question somewhat more colourfully: "If the provincial government were to say to the municipalities, or the shareholders, or a substantial number of these LDCs, "Eat your vegetables; it's good for you" - forget about the incentives; just do this in the public interest - my question is: Is there any evidence, sir, that conservation and demand management could not be achieved effectively if the government just said "You must do it"?"

Arguably, the government has already tried asking LDCs to "eat their vegetables" and the difficulty that the Board experienced getting utilities to act upon the Minister's third tranche directive is strong evidence that mandating alone is insufficient. The need for assured cost recovery was likely the predominant concern at that time since the ability to earn a return on capitalized expenditures provided some positive incentive, but the LDC's lack of response demonstrated that even a slight risk of non-recovery was enough to ignore the mandate.

However, the important question is surely not: 'Will LDCs spend money if told to do so and provided with the cash?'. The question must be: 'Would they do a good job?'. Hence the second response: mandating spending will surely cause spending to occur but not necessarily smart spending that achieves maximum conservation benefits. Alternatively, mandating conservation (as opposed to spending) will not ensure that the conservation is achieved most cost-effectively. A TRC based SSM gives the utilities an incentive to both maximize conservation and minimize costs since TRC is the net of the two.

The third response was that mandating implies that there is a negative consequence for failure. It is in effect a penalty based system. The witnesses responded by noting that “you catch more flies with honey than vinegar”.

In summary, an incentive will increase savings and if the incentive is designed appropriately it will increase cost-effectiveness of programs, benefiting all customers.

The 5% proposal and alternatives thereto:

Three questions arose in conjunction with the proposed incentive of 5% for each and every dollar of TRC SSMI. Is 5% sufficient? Is 5% too rich? Is a reward for all conservation rather than above average performance appropriate?

Mr. Goulding suggested that a reward for a successful program should have the potential to improve utility profits by as much as 5% (Ex. C.1 at p. 50). If we assume that the net TRC benefit to spending ratios are in the 2:1 range typically experienced among electric utilities rather than the 7:1 that Enbridge has attained at its peak, and if we assume spending at the higher level considered in Mr. Gibbons’ sensitivity analysis, $90 million is spent per annum, and the net TRC benefits would be 180 million dollars per year. (Ex. C.3 at pp. 9-10) This would generate a 14 basis point impact on after tax RoE. At a 7:1 ratio the figure rises to 40 basis points which is approximately 5% of the allowed RoE. Accordingly, the 5% could meet Mr. Goulding’s test of sufficiency, but only at an extraordinarily high TRC to program cost ratio. This suggests that the 5% is certainly not too rich and may be too small to be optimal, but is in the right ballpark.

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.

Further, it is possible to base a reward on spending to TRC ratios rather than TRC alone. The danger is that this will encourage lost opportunities. An LDC will seek to maximize the ratio rather than the TRC. For example, efficiency programs would tend to focus only on high TRC measures to avoid ‘diluting’ TRC to spending ratio results by delivering less TRC intensive but still cost-effective measures at the same time. In that scenario the opportunity to deliver the less TRC intensive measure may be lost as the transaction costs of subsequent separate delivery may be prohibitive. If a utility program delivery agent is in a commercial building installing better fluorescent bulbs he may be able to cost-effectively install better ballasts, reflectors and controls, but a separate customer contract and trip to do so may not be cost justified. This is why DSM experts often favour comprehensive programs. Delivering comprehensive programs can lead to higher spending to TRC ratios and still be better for society.

Mr. Heeney prepared evidence on behalf of CEEA that suggested that a TRC based SSM was appropriate but that the Board may also want to consider simpler incentive alternatives based on kWs or kWhrs. Mr. Chernick pointed out that simple kW incentives would not value savings off-peak, would not place higher value on longer-lived measures, and would not favour more cost-effective measures and programs. Simple kWhr incentives would recognize the added value of peak reduction, would not place higher value on longer-lived measures, and would not favour more cost-effective measures and programs. He recommends the TRC as the way to incent both savings and cost-effectiveness. (See discussion at v. 9, pa 903-908) Mr. Heeney suggested that the mechanisms could be altered to import factors such as life of the measure. However, once the mechanisms are tweaked to capture these factors they are in effect the same as the TRC and there is little difference in simplicity.

GEC submits that the simple 5% TRC incentive be maintained in 2006 but that the Board advise the LDCs that in future years it will be prepared to look at incentives that will require a higher level of performance from the utilities. Implementation details are discussed in part G, below.

D. Conservation Expenditures Variance Account (CEVA)

The CWG proposed a CEVA (similar to the DSMVA utilized by the gas utilities). Mr. Chernick in supporting the proposal clarified that the account should capture only the expenditures that are expensed and the carrying cost charges on capital investments.

A CEVA serves several purposes:

- ensuring cost recovery for the LDCs
- avoiding the need for highly accurate spending forecasts during the uncertain start up phase
- reducing the need for an extensive budget approval process at the front end of the regulatory cycle

- enabling utilities that experience highly successful program uptake during the rate year to respond to customer requests without facing a penalty

- ensuring that budgeted but unspent funds are returned to ratepayers. This enhances fairness and removes the incentive to underspend.

For all of these reasons the GEC submits that such an account is appropriate, particularly in the early years of electricity C&DM.

E. Spending Guidelines

Both Mr. Chernick and Mr. Goulding suggested that the Board should enunciate a spending level above which a more rigorous application process would be triggered. Both experts based their recommendations on the experience elsewhere which has demonstrated levels of spending that have not exceeded the point of cost-effectiveness. Mr. Goulding suggested 5% of gross revenues. Mr. Chernick suggested a more conservative $250/MW which is equivalent to approximately 3% (about $350 million in total in the unlikely event that every utility spent at that level).

Mr. Chernick indicated that his guideline was for all customer side C&DM spending including third tranche spending in that category in the year and excluding utility side expenditures and smart meters. Given that the third tranche applications share a common theme of a small allocation to customer side efficiency programs, their inclusion in the guideline is not a significant factor. As Mr. Chernick noted by way of the example of Veridian (C.2, p. 7), only 10% of funds are earmarked for customer side conservation. Ten percent of one year's worth of the three year $225 total third tranche is only $7.5 million.

Mr. Goulding went further than Mr. Chernick and suggested a minimum of 1% (about $120 million) would be appropriate and an expectation in the range of

2-3% ($240-360 million) would also be appropriate (v.9, p. 117 - 120). Mr. Goulding appears to include third tranche funds spent on customer side conservation efforts in the year (see v. 8, para. 340).

Mr. Chernick and Mr. Gibbons both noted that they would not expect actual spending to be at that level in the first year. Rather, the guideline is a trigger for higher up front scrutiny, not a prediction or requirement for spending, nor is it a cap.

The GEC strongly supports the enunciation of such a guideline as it would be an indication from the Board that it is encouraging aggressive C&DM programming with the only limit being cost-effectiveness.

F. Capitalization Policy

There was some discussion about the merits of capitalizing (for purposes of rate setting) the costs of programs that encourage customer side conservation (although they may be expensed for tax purposes as the utility does not own the asset). Given that most measures provide multi-year benefits and most programs last several years, in subsequent years there will be a rough matching of the benefits enjoyed by a given generation of ratepayers with the costs they bear without need of capitalization, as new program costs are offset by benefits from past efforts. However, capitalization improves matching of benefit and rate periods in the start up phase and reduces rate impacts in the early years. For these reasons GEC agrees with the position articulated by Mr. Chernick that there are not overwhelming reasons to favour one approach over another. GEC suggests that if the Board views the adoption of a policy favouring capitalization as beneficial, that a simplifying assumption of a 5 year average period be used.

G. Streamlining the process for 90 utilities

A great challenge facing the Board is to devise a C&DM regulatory framework that is effective while not unduly cumbersome or expensive. The participants in the CWG were keenly aware of this challenge and sought to develop a proposal that met these needs. There was a high degree of agreement among CWG participants and among the experts who testified in this case that a workable model should:

- reduce the Board's need to conduct hearings on minutae
- increase the sharing of information and experience among LDCs
- utilize information from other jurisdictions
- enhance economies of scale in the regulatory process
- harness the expertise available from stakeholders
- provide due process for LDCs and intervenors
- reduce regulatory risk and utility disincentives while encouraging excellence in performance

GEC endorses the CWG model and offers the following "12 step" elaboration of the process:

GEC RECOMMENDED C&DM PROCESS FOR CUSTOMER-SIDE PROGRAMS

1) Avoided Costs development should be implemented immediately. If the 2005 panel does not do so[1] the 2006 panel should instruct its staff to immediately retain an expert to produce a set of provincial default avoided costs. Mr. Chernick and Mr. Gibbons both noted that experts are available who could provide such analysis in approximately one month at reasonable cost (v.9, 921).

2) The OEB should invite nominations and select a C&DM Advisory Committee. This process can start immediately. The Board should

select a small number of individuals based on their credentials, the Board's past experience with the sponsoring party, and the need to obtain diversity. The time and expenses of appointees should be paid for by the Board and charged to the LDCs.

3) With the advice of the advisory committee, the Board should retain an expert C&DM Auditor/Advisor.

4) The 2006 EDR handbook should include reference to an LRAM, a simple 5% SSM, a CEVA with a budget flexibility feature, and refer to process details as set out in the items listed below.

5) The EDR handbook should indicate a $250/MW customer efficiency program spending limit (including 3rd tranche allocated to those aspects in the year but excluding smart meters) above which more detailed program justification and cost benefit screening is required in advance. The handbook should specify that all programs apart from limited time pilot projects should pass either the SCT or TRC test of cost-effectiveness.

6) 2006 rate filings should include a forecast of C&DM spending and a brief description of program areas. The forecast may be used to adjust revenues and expenditures utilized in rate setting for 2006 at the LDC's option. Where a forecast is used, the LRAM is a variance only account. Where no forecast is utilized, the LRAM captures the full impact of customer side conservation revenue impact due to utility programs. The CEVA would allow for expenditures not forecast or beyond forecast within the spending guideline (The CWG recommended limiting this to 120% of budget) and would capture all unspent funding collected in rates. As Mr. Chernick noted at v.9, p. 873, even where an LDC seeks to adjust forecast revenues and expenditures prospectively, no load forecast is required for that purpose.

7) LDCs (or their agents) may submit proposed default inputs to the advisory group for pre-approval. The group and the Board's Auditor/Advisor would also gather suitable inputs utilized in other jurisdictions such as B.C. and California. Some inputs, such as measure life and energy use of the new technology, may be transferable whereas others, such as efficiency of the typical technology being replaced, might be specific to Ontario or market areas in Ontario. Free ridership will often be specific to the locale, sector or in some cases program design. Avoided costs would be specific to Ontario. The Auditor/Advisor could also propose attribution rules where programs are delivered cooperatively with other utilities or organizations like NRCan or the Conservation Bureau.

The recommendation of the Auditor/Advisor would be posted on the web for at least one month to allow the opportunity for LDCs and intervenors not represented on the advisory group to comment.

The Auditor/Advisor and committee may alter its recommendation or otherwise respond to comments received after which the recommendation and any comments received are submitted to the Board for decision. This process is the "big S" stakeholder process as it was referred to in the hearing. LDCs will also find it useful to conduct informal "small S" stakeholder consultations with particularly affected local groups or businesses, but such efforts will be at the LDCs option. These processes could occur before, during, and after, the 2006 rate application process.

Any inputs the Board pre-approves in this process may be relied upon for LRAM and SSM clearance at the end of the process (without true up) by any LDCs where the input is demonstrated to be applicable.

8) The Auditor/Advisor will also facilitate sharing of program and portfolio design information (a role which may evolve as the Conservation

Bureau role evolves) in the same manner that other clearinghouses do, but with emphasis on the Ontario context. (See for eg. the PG&E multi-utility Best Practices information available at: http://www.eebestpractices.com/index.asp)

9) At the end of the rate year, each LDC will prepare (or retain expert assistance to prepare) and submit to the committee an evaluation report that includes the statistics that are listed in the CWG report. The LDCs would be responsible for certifying their own participant counts but be potentially subject to spot audit by the Board's Auditor/Advisor. A template for the reports, data and calculations would be published in advance by the Auditor/Advisor. Required information would include the items listed in the CWG report (ex. D7.3, p. 37, tab 4, CWG#6 p. 20)[2]:

10) The same review, comment and recommendation process used for inputs will be used for evaluations prior to the Board making its determination.

11) Any party may petition the Board for a written or oral hearing on any of the recommendations in the usual manner that is applicable to all rate applications, however, the Board having had the benefit of the Audit/Advisory and comment process will presumably find the number of occasions warranting a further written or oral hearing to be few. The evaluation reports once accepted (after amendment if required) will form the basis for the clearance into rates of the CEVA, LRAM, and SSM accounts.

12) The Auditor/Advisor may also make recommendations to the Board based on the evaluation reports and other new information to update pre-approved inputs applicable in subsequent periods. These updates and any other guidelines the Board may wish to issue (such as those recommended in CWG#11)[3] would be published on an ongoing basis by the Board.

Mr. Warren in his cross-examination of Mr. Goulding at v. 8, para. 377 *et seq.* presented a list of 9 or 10 tasks and decisions that the Board faced: setting budget, rules for project screening, capitalization policy, need for and design of an LRAM, need for and design of an incentive, monitoring and evaluation protocols, attribution rules, regulatory review process, utility side programs policy, development of avoided costs.

GEC submits that a timely decision by this panel on the matters addressed in parts A through F of this submission coupled with the adoption of the process set out above will put in place a clear, timely, and manageable process that deals with each of the Mr. Warren's tasks (apart from utility side program policy which we address below).

GEC's recommendations respect the need for regulatory oversight, due process and economies of scale, while avoiding the need for the Board to descend into micro-management. The approach is a practical way forward that respects the competing demands on the Board's time and the limited resources of the LDCs and intervenors.

H. EDR Handbook Entries for C&DM

Items 4, 5 & 6 listed above in part G include the matters that must be addressed in the spreadsheet associated with the 2006 EDR Handbook. Specifically, the Board should include:

13) An opportunity for LDCs to indicate whether they wish to have deferral/variance accounts opened for 2006 LRAM, CEVA and SSM (at 5% of TRC).

14) An entry to indicate expected C&DM spending and to attach proposed program general descriptions. A requirement to include TRC screening results by program where expected spending exceeds $2.50/MWh.

15) An option (mandatory after 2006) to increase the 2006 revenue requirement to include the C&DM customer side programs budget. Where the revenue requirement adjustment is sought, CEVA is mandatory (to enable recapture of unspent C&DM dollars).

16) An option (mandatory after 2006) to forecast C&DM program customer side impacts and adjust sales volume, and thus revenue, downwards. Where this option is taken, any LRAM will be prospective and be a variance account only. Where this option is not taken the LRAM will be retrospective and cover the full impact of C&DM customer side programs. (For a full description of the LRAM see Exhibit C.3)

17) In addition GEC suggests that the Board should include in the prose portion of its handbook an outline of the C&DM regulatory process similar to part G, above.

I. Loss Factor Incentives

Mr. Chernick points out that the critical need for revenue protection and an explicit incentive for customer conservation programs does not apply to utility side initiatives including loss reduction. These efforts are already part of utility culture and practice, are already funded in rates, do not reduce revenues, and are usually capital intensive and therefore add to rate base and return.

Mr. White agreed that the problem of late has been due to uncertain or delayed adjustment to rate base.

Pollution Probe proposes that the incentive to reduce losses would be enhanced if variances in losses experienced in the rate period accrue to shareholders rather than flowing through to rates. Mr. White testified that in his view the exposure that this would create for financial penalty or windfall for loss factor changes not within the influence or control of the utility was unacceptable. However, Mr. Chernick noted that such impacts would often be systematically offset by other factors. For example, if unusual load growth was experienced the utility would see higher losses but also higher revenues in the rate period. Mr. Gibbons suggested that many of these changes could be foreseen and forecast.

Mr. Chernick offered two alternatives. In his written evidence Mr. Chernick suggested that regular opportunities to adjust rate base, and an opportunity to seek rate relief in extraordinary situations should suffice. (For example a major unforseen closure of a major customer in a small utility). In his oral evidence Mr. Chernick added that if a greater incentive along the lines of the Pollution Probe proposal is to be adopted it could be moderated and could, for example, visit 10% of loss changes on the utility rather than 100% (v.9, 923-930).

GEC supports either of these alternatives.

All of which is respectfully submitted this 14th day of February, 2005

David Poch

On Behalf of the GEC

Endnotes:

1. On February 17th GEC will be asking the 2005 panel to have Hydro One immediately develop these values or direct OEB staff to engage an expert to expeditiously develop the values.

2. From CWG#6: ALL LDCS ANNUALLY TO REPORT:

- ANNUAL KWH, PEAK KW AND PEAK KVA SAVED;
- ANNUAL KWH, PEAK KW AND PEAK KVA SAVED, AS A PERCENTAGE OF THE UTILITY'S TOTAL KWH DELIVERED, PEAK KW AND PEAK KVA RESPECTIVELY, BROKEN-OUT ACCORDING TO MAJOR CUSTOMER SEGMENTS (E.G., RESIDENTIAL, COMMERCIAL/INSTITUTIONAL, INDUSTRIAL);
- CONSERVATION EXPENDITURES; AND
- CONSERVATION EXPENDITURES PER KWH DELIVERED, PEAK KW AND PEAK KVA, BROKEN OUT BY MAJOR CUSTOMER SEGMENTS.
- NET PRESENT VALUE OF TRC BENEFITS, BROKEN-OUT BY MAJOR CUSTOMER SEGMENT;
- FIRST YEAR AND CUMULATIVE RATE IMPACTS OF THEIR PORTFOLIO OF CONSERVATION PROGRAMMES, BROKEN OUT BY MAJOR CUSTOMER SEGMENTS.

THE EVALUATION REPORTS FOR UTILITIES THAT ARE SEEKING AN SSM REWARD SHOULD ALSO PROVIDE THE FOLLOWING INFORMATION *FOR EACH CONSERVATION PROGRAMME*:

- TARGET MARKET;
- NUMBER OF PARTICIPANTS;
- DOLLARS SPENT PER PARTICIPANT;
- LIFETIME ELECTRICITY SAVINGS (KWH, KW AND KVA) ACHIEVED; AND
- TRC TEST INPUTS AND RESULTS BY MEASURE AND PROGRAM.

3. Exhibit D 7.3, tab 4, page 47, from CWG#11 para 9:

Programme development guidelines:

a) The utilities should develop a diversified portfolio of conservation programmes to minimize cross-subsidization. A portfolio which will permit all utility customers to participate in at least one conservation programme during the next three to five years is recommended. Specifically, the utilities should design programmes to overcome market barriers, beginning in 2005 or 2006, to enable all customer groups (e.g.,low income customers) to share in the benefits of conservation programmes as quickly as possible.
b) To the fullest extent possible one customer segment (e.g., industrials) should not subsidize another customer segment's (e.g., residential) conservation programmes.
c) In order to maximize ratepayer benefits and avoid duplication of effort, the utilities should be encouraged to co-operate, where appropriate, with each other, the proposed Ontario Power Authority and Ontario's gas utilities to develop cost-effective conservation programmes.
d) The Board should also encourage the utilities to contract out some or all of their conservation programme design, delivery and evaluation if this option will lead to reduced costs or higher value-added.
e) To minimize customer costs and better address the Government's conservation goals, the utilities should take care not to overlook lost opportunity programmes in addition to discretionary retrofit programmes. (Lost opportunities programmes are conservation programmes that focus on situations where an event is occurring such as a building being constructed or a piece of long-lived equipment being replaced. In these situations failure to implement a conservation measure at the same time will mean either a considerable delay until the opportunity arises again, or a much higher cost if the premature retirement of the new equipment is required.)