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February 14, 2005

VIA FAX and EMAIL

Mr. John Zych
Board Secretary
Ontario Energy Board
P.O. Box 2319
26th Floor
2300 Yonge Street
Toronto, ON
M4P 1E4

Dear Mr. Zych:

Re: Vulnerable Energy Consumers Coalition (VECC) Final Submission re: Rate Handbook for Electricity Distribution Rates RP-2004-0188

As Counsel to the Vulnerable Energy Consumer's Coalition (VECC), we have enclosed the final submission of VECC with respect to the above-noted hearing.

Yours truly,

Original signed

Sue Lott
Counsel for VECC

RP-2004-0188

ONTARIO ENERGY BOARD

IN THE MATTER OF

**THE
2006 ELECTRICITY DISTRIBUTION
RATE HANDBOOK**

Final Submission of

VULNERABLE ENERGY CONSUMERS COALITION

February14, 2005

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1 INTRODUCTION

1.1 Background

Although VECC was not present in the Hearing Room except during oral testimony on issues on which it sponsored evidence, VECC's consultants have monitored the oral phase of the hearing by way of the Internet broadcast and transcripts during the proceeding.

This final submission is structured in two Parts in order to provide the Board an understanding of VECC's position on the evidence and unresolved Issues related to the finalization of the 2006 EDR Rate Handbook and 2006 EDR Regulatory Process.

Part A -Detailed Submissions On 2006 EDR Rate Handbook

- Issues on which VECC took a lead in providing Expert Evidence
- Issues of general importance to residential ratepayers and/or critical importance to VECC's constituency
- Issues related to 2006 Conservation and Demand Management (C&DM) programs

Part B - Summary of Positions on Unresolved Issues in Tabular Form

- VECC Positions or view regarding alternatives presented on the remaining unresolved issues identified in the Handbook
- General comments on other aspects of the Handbook

1.2 2006 EDR Rate Process and Rate Handbook

The 2006 rate applications by Electricity Distributors will be the first following a 5 year Performance Based Regulation (PBR) regime (2000-2005) which has been modified by a government imposed rate freeze instituted in 2003.

As the Rate Handbook (RH) outlines, the construct for 2006 rates is a Cost of Service (COS) approach under which reasonably incurred costs are reviewed and a revenue requirement approved by the Board. The revenue requirement is allocated to the service classes and rates are designed to recover the revenue requirement based on a forecast of delivered energy.

The EDR Model for 2006 differs from a full cost of service rate application in that it does not use a forward 2006 test year. Rather the standard application will request a revenue requirement for 2006 based on 2004 actual costs adjusted for specific significant events (Tier1). Some utilities may claim hardship under the Tier 1 rules and may make a Tier 2 application with considerably more supporting information. Some other utilities may choose to make a full cost of service application with a forward 2006 test year.

VECC submits that regardless of the type of application, the resulting 2006 distribution rates must be just and reasonable. The Board must be vigilant to ensure that other than the costs related to reaching the full allowed Market Based Rate of Return (MBRR) on common equity, and recovery of legitimate costs of regulatory assets to be recovered over 3 years, additional cost pressures that have built up in the PBR plan period are not passed on to ratepayers. During the period that rates were frozen (except for MBRR and Regulatory Assets) the net increase should have been governed by the PBR formula of inflation minus productivity (IPI - 1.5% per year). This should be a guide to whether the 2006 rates are reasonable.

PART A -DETAILED SUBMISSIONS ON 2006 EDR RATE HANDBOOK

2 HANDBOOK SECTION 4.4 - INTEREST FOR CWIP AND DEFERRAL ACCOUNTS

The importance of this issue is that the 2000 Rate Handbook and first generation PBR had no specific regulatory treatment for the allowed carrying costs of Construction Work In Progress (CWIP) and no standard treatment for interest on deferral account balances. This has resulted in the use of long-term interest rates by the distributors unless a rate was specifically prescribed by the government (such as that for 2005 C&DM Costs). This approach adopted by the electric distributors is not in conformity with regulatory practice elsewhere, or even with the practice the Board has applied to regulated gas utilities under its jurisdiction.

VECC's concerns with this method are articulated on Issues Day to be as follows:

1) Absence of a Board approved allowed interest rate, ratepayers may be paying too much in carrying costs so rates may not be just and reasonable and,

2) A standard regulatory approach is required for the 2006 Rate Handbook.

2.1 Evidence of Mr. G. Matwichuk Stephen Johnson Chartered Accountants

With agreement from the Board, VECC sponsored an independent expert, Mr. Greg Matwichuk of the firm of Stephen Johnson Chartered Accountants, to review regulatory practice in the area and provide recommendations on an appropriate approach that would fit with the requirements of the 2006 Rate Handbook and the 2006 EDR Process.

Mr. Matwichuk's Report dated December 13, 2004 made the following conclusions[1]

> As contemplated in the EDR Handbook, there are two distinct alternatives for carrying charges associated with CWIP:
> **"Alternative 1:** the embedded cost of debt (GAAP)"; and
> **"Alternative 2:** some form of short-term debt rate"
> Based on the review in this evidence, there is a third alternative:
> **Alternative 3:** AFUDC using the WACC or IDC using long-term debt cost. With respect to CWIP the issue is fairly straightforward. Given the regulatory principles, history and generally accepted regulatory practice, the appropriate carrying charge for CWIP would be AFUDC (using rate of return on rate base) in the case of utility whose capital structure includes an equity component and IDC for a utility that is essentially financed by debt. Short-term debt rates are not typically employed in the context construction assets.
> Based on my analysis, I recommend **Alternative 3**.

With respect to the issue of interest on deferral accounts Mr. Matwichuk comments are as follows:

> The less definitive issue is whether deferral accounts should attract short-term financing. In the alternative they would receive a long-term debt rate or even rate base like treatments. There are no hard and fast rules to determine the appropriate treatment. However, as outlined above I set out a number of considerations and criteria with respect to an assessment.
> First, consider the 3 alternatives contemplated in the EDR Handbook for deferral accounts:
> **"Alternative 1:** the embedded cost of debt (GAAP)";
> **"Alternative 2:** some form of short-term debt rate"; and
> **"Alternative 3:** deemed debt rate (5- to 10-year rate)"28.
>
> Based on the data presented, my review of these accounts and the practices in various jurisdictions, it is more likely that these accounts have attributes that would attract short

[1] Ontario Energy Board ("OEB" or the "Board") RP-2004-0188
For Vulnerable Energy Consumers Coalition Evidence of M. G. Matwichuk
December 13, 2004

term financing. While an account such as the transition cost deferral may be a one time balance to be amortized over a period of years, that period is very short which would be more amenable to short term financing. Deferral accounts, such as the ongoing retail settlement variances appear to be of a blended nature over time and where one would expect some volatility, would be better accommodated by short-term debt instruments. Given a utility's ability, in general, to actually carry out short term financing for these balances, awarding a long term debt rate or a rate of return on rate base would likely provide an opportunity to earn an excessive return on equity. Historically, this Board has implemented different interest rates for carrying charges on deferral accounts, including short-term debt.

To borrow a format from the EDR Handbook, the short-term debt rates applicable to the Electric LDCs for 2006 might look like the following:

TABLE 1

Size-Related Debt Rate Formula				
Utility Size	***Rate Base***	***Deemed ST Rate***	***Deferred Accounts Aggregate Balance Greater than 10% of Rate Base***	***Financial Distress***
Large	*> $1.0 billion*	*Prime less 1.75%*	*10 year debt rate to WACC*	*WACC*
Medium -Large	*$250 million - $1.0 billion*	*Prime less 1.00%*	*10 year debt rate to WACC*	*WACC*
Medium -Small	*$100 million to $250 million*	*Prime less 0.50%*	*10 year debt rate to WACC*	*WACC*
Small	*< $100 million*	*Prime*	*10 year debt rate to WACC*	*WACC*

The approach in Table 1 would likely result in a reasonable approximation of the cost incurred by a utility to finance the deferral accounts. It has the added benefits of accessibility, transparency, administrative simplicity and, thereby consistent with the approach being proposed for long term debt costs.

What accounts would you suggest be considered for the use of short term and long-term rates?

I have not completed a thorough review of the uniform system of accounts, but it is apparent that the short term rates should be applied, in accordance with Table 1, to the deferral accounts associated with transition costs, pre-market opening cost of power variances and post-market opening retail settlement variances, as outlined in Q&A 12 above. As discussed above, long term rates, IDC or AFUDC would be appropriate for use with CWIP. Further, a range of 10 year debt rates and WACC, would be appropriate for carrying charges where certain conditions are met, with respect to deferral accounts, as outlined in Q&A 30.

2.2 VECC Recommendations on Interest Rate for CWIP and Deferral Accounts

In this proceeding, the evidence of Mr. Matwichuk has not been contested by any party. Hydro One had provided a short commentary, the thrust of which is that the Board should deal with the disposition of balances in deferral accounts in a timely manner and not allow them to age unnecessarily.

The recommendations offered by Mr. Matwichuck are based on sound research and strike a balance between the interests of the utility and its shareholder and the interests of ratepayers. For these reasons, VECC submits that the Board should adopt the recommendations of Mr. Matwichuk and incorporate Table 1 of his evidence into Section 4.4 of the 2006 EDR Rate Handbook.

3 HANDBOOK SECTION 13 - MITIGATION

The draft 2006 EDR Rate Handbook addresses three aspects of rate mitigation:

13.1 Impact Analyses

13.2 Mitigation Methodologies

13.3 Rate Harmonization

On Issues Day the Panel made the following determination:

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

3.1 Evidence of Econalysis Consulting Services

Accordingly VECC retained the services of Mr. W. Harper and Ms. J. Poon of Econalysis Consulting Services (ECS) to provide evidence including:

- Templates setting out the information LDC's will be required to provide regarding "rate impacts". This would likely address:
  - Average Overall LDC rate increase, i.e., total revenues at proposed rates / total revenues at current rates. (Note – Issues may also involve what level of usage to use in the calculation)
  - Average rate increase by customer class; i.e., total class revenues at proposed rates / total class revenues at current rates.
  - Bill impact analyses to be performed.
- Guidelines with respect to what would be "reasonable/non-contentious" levels of rate increases/bill impacts (for above aspects)
- Guidelines as to options or requirements for LDC's who exceed these guidelines:
  - For overall average increase
  - For customer classes
  - For customer bill impacts.

The ECS Evidence filed on December 13, 2004 made the following conclusions:

> Class and Customer Rate Impacts
>
> There could well be variations in the average rate/bill increases attributable to each customer class or individual customer. In order to highlight the potential impacts, LDCs should be required to include in their Applications impact analyses at both the customer class and individual customer level. LDCs should work to limit the impacts associated with cost/allocation and rate design to acceptable levels.
>
> Filing Requirements
>
> To this end, the rate/bill impact-related filing requirements for each customer class should include:
>
> 1. The average increase in distribution rates for each customer class (i.e., the percentage increase in revenues from applying the proposed distribution rates as opposed to the current distribution rates to the test year billing quantities), prior to any rate harmonization.
> 2. The increase in individual customers' distribution and total bills (over a range of monthly usage values for each customer class) forecast for 2006 based on the cost allocation/rate design as proposed by the LDC, prior to any rate harmonization.

3. For those classes where rate harmonization (partial or full) is proposed, the increase in customers' distribution and total bills (over a range of monthly usage values for each customer class) forecast for 2006 based on the "harmonized" rates proposed by the LDC.

Rate Impact Guidelines

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

1. The increases in a customer class' average distribution rates due to cost allocation changes and harmonization should be limited to the all customer average increase (i.e., the maximum customer class increase would be double the all customer average increase).

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

3.2 Reply Evidence of PA Group

Hydro One retained the PA Consulting Group to prepare reply evidence. This was filed on January 10, 2005 the PA Group was less supportive of prescriptive filing requirements based on impact or the requirement for mitigation.

3.3 Comparison of ECS and PA Group Solutions on Mitigation

VECC has prepared a comparison between the ECS Evidence and the PA Group Reply as a basis to formulate its recommendations to the Board

Table 3

Rate Impact Categories and Filing Requirements

ECS Proposal			**PA Group Proposal**		
Filing Requirements dependent on Rate Impact			**Standardized review based on Rate Impact**		
Category	**Definition**	**Filing Requirements**	**Category**	**Definition**	**Filing Requirements**
#1	distribution rates increase 8% or less	No additional requirements.	#1	Annual inflation since last increase	Standard-no additional requirements
#2	distribution rates increase > 8% but < 16%	Variance analysis required	#2	No threshold specified	Additional information required
#3	distribution rates increase >16% but < 25%.	Variance analysis required and justification for spending levels			
#4	distribution rates increase >25%	Variance analysis and justification required plus mitigation plan			
Rate Mitigation Plan or explanation should be provided for Category 4 only			Rate mitigation formulaic benchmarks should be rejected and if adopted be based on unbundled utility		
Rate harmonization impacts should be assessed as an additional layer			Rate harmonization is utility-specific and should not be standard procedure in Handbook		

Sources: ECS views adapted from Table 14 of ECS evidence found on page 37

PA views from Sections 1.1 and 1.2 of Report

3.4 VECC Recommendations on Mitigation

VECC suggests that when considering the weight that should be placed on the solutions proposed by ECS and the PA Group, the Board should note that the ECS solution was based on an analysis of historical rate increases for a sample of 28 Ontario Distribution Companies. The PA Group relied on US experience and did little Ontario-specific situational analysis.

VECC recommends that the Board incorporate the following guidelines into Sections 13.1 -13.3 of the 2006 EDR Rate Handbook.

Section 13.1

- Rate impact analyses are required for all customer classes as per the requirements in the Draft 2006 EDR Rate Handbook.

Section 13.2

- Detailed support for any rate mitigation measures must be provided. The Board has already indicated that changes to the fixed/variable split are to await the cost allocation studies scheduled for 2007.
- If the rate increase exceeds the guidelines recommended by ECS then the additional filing requirements as specified by ECS should be triggered. These should include any rate impact mitigation as per ECS Category 4 (>25% on distribution rates).

Section 13.3

- Distributors should file a rate harmonization plan as per Alternative 1. This should take into account the rate impact guidelines in Section 13.2.

Low and Fixed Income Customers

Both consultants acknowledged that the ability of residential customers to absorb increases in distribution rate increases as well as other costs, are not homogeneous. In particular, low and fixed income customers are particularly vulnerable in this respect. Since low-income does not necessarily mean low electricity use, there is no immediate basis to identify such customers as part of the rate setting process. However there are two important considerations in assessing the rate impact analyses. The first is to be conservative in setting the thresholds for providing additional information and a rate mitigation plan. The second is to reject solutions such as changes to the fixed/variable split that may disadvantage low-income customers disproportionately.

4 HANDBOOK SECTION 14 - COMPARATORS AND COHORTS

There are two subsections in the draft 2006 EDR Rate Handbook 14.1- Methodology, and 14.2 Filing Requirements

4.1 Evidence of R. Camfield Laurits R. Christensen Associates

Board staff retained Robert Camfield, Laurits R. Christensen Associates, Inc. to assess whether or not the Comparators and Cohorts mechanism is feasible for Ontario LDCs - *i.e.*, a proof of concept.

The purpose of the study, as outlined in the Report, was to assist the Board and its staff to:

1) determine whether a Comparators and Cohorts mechanism is feasible and can serve as a practical tool to assist in the processing of rate applications for rebased rates in 2006;
2) determine a basis for the comparison of costs of Ontario’s electricity distributors. These cost factors are referred to as Comparators; and,
3) determine the data and information reporting elements, with a focus on data not currently reported.

The purpose is to gain efficiency and effectiveness within the regulatory process of determining LDC rates for retail distribution services.

Consultants Findings and Recommendations

The consultant’s findings are:

> The Comparators and Cohorts mechanism, for purposes of highlighting cost anomalies

within the LDC rate applications within the 2006 EDR, is viable. We have been successful in finding statistically significant relationships between cost indicators and cost drivers.

While the 2002–2003 LDC data are limited both by inconsistency in reported information and by data omissions, and limited in the range of information, it is clear that underlying relationships exist and indeed have been discovered in the exploratory proof of concept analyses presented herewith.

The Board should pursue development of the Comparators and Cohorts to assist Board Staff in the processing of LDC rate applications. Should the Board and its Staff pursue the development of Comparators and Cohorts for application in the 2006 EDR, it is necessary that specific data and information elements be provided by the LDCs. The reporting requirements are defined in the body of the report.

LDC costs should be organized and reported for unbundled distribution services, and the Comparators and Cohorts mechanism, should it be pursued, should be implemented for each service, Unbundled services include Wires and Interconnection Service, Settlements (billing and collections), and Customer Service categories. Organizing the costs of distribution in terms of these unbundled services will be necessary to gauge LDC performance and to identify the costs of possibly expanded customer service activities of the LDCs in the future.

The data and information as currently filed are incomplete and inaccurate, and need to be augmented with key data. The supplemental data should be filed by the LDCs in coordination with their rate applications. The data must be accurate. Currently, the reported data appear to contain considerable noise, though it has not seriously impaired the success of the Proof of Concept test and we have sufficient confidence that the Comparators and Cohorts mechanism is indeed feasible. The overall objective of course is to streamline the overall regulatory process and improve efficiency of regulation. And while it is necessary to augment the data as filed, the requested data as listed and discussed within the body of this report does not appear to be burdensome for the LDCs.

4.2 Reply Evidence of M.Lowry Pacific Economics Group

Hydro One retained Dr. Mark Lowry of Pacific Economics Group to Review the Camfield Report. Dr. Lowry did not accept that the methodology proposed by Camfield would yield high quality results and recommended several modifications to the methodology. His main conclusions are as follows:

Identification of Anomalies
The (Camfield) report devotes little attention to how the C&C results would ultimately be used to identify cost anomalies. The imprecision of the methodology and imperfections

of the data should be duly recognized. Statistical tests of efficiency hypotheses are desirable due in part to their ability to integrate consideration of a method's precision.

Use of the Results

The experimental character of the C&C methodology should be carefully considered in deciding how determinations of anomalies are used. It seems appropriate to use the results only to screen rate applications and identify those that merit more detailed review.

Role of Benchmarking in Regulation

Camfield's more general discussion of the role of benchmarking in regulation focuses chiefly on the issue of regulatory cost. His discussion does not give balanced consideration to the quality of decisions that would result from the C&C process. It would be desirable for the Board to recognize the quality issue and the potential impact of inaccurate benchmarking methods on operating risk in its final C&C decision.

Camfield's Conclusions

Camfield asserts that he has proved the feasibility of the C&C concept and recommends its implementation. We find that the results reported do not by themselves provide sufficient support for proceeding on the course Camfield recommends. While he properly acknowledges the serious deficiencies in the available data, the collection of better data will not by itself make the C&C approach acceptable. The methodology should, in fact, be changed in several ways if additional work is to be performed. Important dimensions of this mid-course correction include:

Exclusion of capital cost as a performance variable
Consolidated treatment of customer care expenses
Approaches to cost modeling that recognize substitution possibilities
Reporting of key clustering analysis statistics
Reconsideration of comparators
Development of statistical tests of efficiency hypotheses

4.3 VECC Submissions on C&C Methodology and Data Requirements

While the oral cross-examination phase of Camfield and Lowry was a case of experts at ten paces, VECC believes that several useful conclusions can be drawn.

1. The work of Camfield has demonstrated that once developed, C&C benchmarking is a useful regulatory tool for application to the Ontario Electricity Distribution Sector.
2. The time and cost to develop the methodology and collect the required data is considerable and this may not be feasible for a rigorous application for 2006 rates.
3. The objectives for C&C for 2006 should be to identify and fix methodological problems, and define a minimum set of data requirements to allow C&C to be used by Board staff and intervenors as a screening tool in the review of the 2006 EDR Applications

4. In the longer term, development of C&C benchmarking should continue under Board Staff auspices. However the requirement for a rigorous cost allocation model is the first priority for 2007 and once this is done' it should also improve utility cost data quality and reduce the noise now evident in the available data.

5 CONSERVATION AND DEMAND MANAGEMENT

5.1 Introduction

As pointed out by one of the Board panel members, 2006 is the first complete rate review since the amendments to the OEB Act resulting from Bill 100.

> MR. SOMMERVILLE: Ms. Lea, just before you begin, most of the work that was done with respect to the C&DM materials was done prior to the passage of Bill 100, and there's a matter that the Board would like parties to address in their submissions that relates to the change in the objects of the Board occasioned by the passage of Bill 100. 855
>
> As you all know - and I'm not asking you to comment on this; this is really just for the record and for the advice of parties' - the objects of the Board were radically changed by Bill 100. The seven incumbent objects were, in effect, deleted and substituted for two new ones. In addition, Bill 100 also had the effect of creating the OPA and endowing it with certain objects. And the Board would appreciate it if the parties could address the meaning of those changes for the purposes of our consideration of the C&DM materials.

In simple terms, condensing of the Board's objects from 7 to 2 has the effect of increasing the weight and emphasis that the legislation requires the Board to place on protecting consumers.

VECC suggests that the 2006 EDR process is the proper place to put in place a regulatory framework that will protect consumers, by the Board ensuring that *second generation C&DM* expenditures are cost effective and provide direct and indirect benefits to electricity consumers. The first generation C&DM programs should be considered a special case that was approved without "a heck of a lot of evidence" based on the Ministers direction to the utilities. Some of the costs of these programs (estimated at about $28 million for the 6 large utilities) will carry forward into 2006 and be included as part of the 2006 revenue requirement. The Board has no basis to determine if these programs are cost-effective from a consumer's cost/benefit perspective.

A review of the main C&DM evidence is provided as follows.

5.2 Evidence of London Economics International (LEI)

Board Staff retained London Economics International AJ Goulding/Gilan Sabatier to review specific ratemaking matters that impact the distribution sector as a whole; such as, regulatory treatment of operating and capital expenditures, revenue protection, and distributor incentives for loss mitigation for efficient distribution and for the customer side of the meter initiatives. LEI was not asked to make any recommendations regarding which alternatives were most appropriate for Ontario. The focus was on compensating utilities with the proper revenue recovery mechanisms and incentives to implement cost-effective C&DM programs.

After reviewing C&DM practice across North America, LEI introduced four prototype models that cover a range of possibilities. Each of these models incorporates an incentive mechanism. Program costs are treated either as an expense or rolled into ratebase.

- Model 1 (pay as you go) provides an example of a C&DM framework that offers a fairly low administrative burden to the regulator. It uses a timely prospective surcharge mechanism to ensure lost revenue recovery and a bonus incentive that rewards the utility in proportion to energy savings. This model's simplicity is attractive to the regulator.
- Model 2 (pay over time) provides an example of a C&DM framework that presents a median level of administrative effort by the regulator depending on the size of the sector. It uses a deferral account to ensure lost revenue recovery and a shared savings incentive that splits energy savings with the consumer. This model is commonly applied and offers benefits to both the utility and the consumer.
- Model 3 (SSM only) provides an example of a C&DM framework that presents a high level of complexity. It uses a prospective shared savings mechanism (SSM), but no lost revenue adjustment mechanism (LRAM). Revenues from the SSM are subject to true up based on actual utility performance. Model 3 provides companies with upfront revenues, but could benefit the consumer by ensuring that incentives actually lead to bill reductions. Model 3 is the most administratively complex of those examined.

- Model 4 (flat rate pricing plus SSM) restructures Ontario rates to be calculated on a flat rate basis. This eliminates the need for an LRAM. The model incorporates an SSM calculated using a retrospective surcharge, meaning this model is also results oriented based on reductions in customer bills. We recognize that such a redesign of Ontario ratemaking procedures may not be feasible before 2008; however it is presented here as one important hypothetical alternative.

LEI concluded that:

> Ultimately, the model chosen in Ontario maybe one of these or some hybrid that contains elements of all our hypothetical models. The appropriate model will depend largely on two factors: the OEB's regulatory objective and the expectations regarding wholesale and retail electricity market outcomes in Ontario. The OEB must decide to what extent it wants to trade-off on the total cost of electricity versus the price of electricity. This will determine the method of evaluation. The choice is between the *Total Resource Cost Test* which measures the net costs of a C&DM program based on the total costs of the program, including both participant and utility costs and the *Rate Impact Measure Test* which measures the direction and magnitude of the expected changes in rates for all customers when a utility implements a C&DM program. The uncertainty surrounding the Ontario electricity market makes selection of the appropriate C&DM model difficult because the value of C&DM is predicated on the opportunity cost of electricity. Given that wholesale market outcomes are uncertain, *cost-benefit analysis of C&DM programs will also be challengin*g. [emphasis added] Ontario does benefit from the fact that its utility system is fully unbundled, meaning C&DM mechanisms do not need to take into account the impact on generation revenues. Other issues to account for in C&DM design include the large number of Ontario utilities, the diversity of service territories and ownership structures, uncertain institutional roles and responsibilities, and the interaction between C&DM design and other elements of rate design such as default supply.

5.3 Evidence of Public Interest Economics

Pollution Probe retained Jack Gibbons of Public Interest Economics to provide evidence on LRAM and SSM for 2006. His recommendations were as follows:

1) To ensure that the electric utilities will not be penalized for implementing effective, customer-side of the meter conservation programmes in fiscal 2006, they should be allowed to recover, in a subsequent rate year, the lost distribution revenues plus carrying costs that they experience between May 1, 2006 and April 30, 2007 inclusive as a result of their energy conservation programmes.
   Scenario #1: Fiscal 2006 rates are not a function of a load forecast, which takes into account the impact of the utilities' conservation programmes.
   A utility's lost distribution revenues, for each rate class, should be calculated by

multiplying the *incremental* reduction in its kWh and kW volumes, as a result of its conservation programmes, by its distribution charges per kWh and kW.

Scenario #2: Fiscal 2006 rates are a function of a load forecast, which takes into account the impact of the utilities' conservation programmes
If the actual electricity savings of a utility's conservation programmes are greater than forecast, the utility should be *allowed* to recover its lost distribution revenues plus carrying charges from its customers in a subsequent rate year. Conversely, if the actual electricity savings of a utility's conservation programme are less than forecast, the utility should be *obliged* to return its *excess* distribution revenues plus carrying charges to its customers in a subsequent period.

For example, for a residential customer class, with no demand charge, the lost/excess revenues will be a function of: (Actual incremental kWh savings due to the utility's fiscal 2006 conservation programmes – forecast incremental kWh savings due to the utility's fiscal 2006 conservation programmes) x distribution charge per kWh.

2) Each utility should be permitted to apply for a Shared Savings Mechanism incentive equal to 5% of the total net bill savings, as measured by the <u>Total Resource Cost Test,</u> that are created by its fiscal 2006 customer side of the meter conservation programmes.

3) The dollar values of the utilities' LRAM and SSM claims should be calculated according to the methodologies outlined in this evidence.

5.4 <u>Evidence of Resource Insight Inc</u>

The Green Energy Coalition retained Paul Chernick of Resource Insight to make recommendations regarding regulatory treatment of C&DM for 2006 and beyond. Mr. Chernick's evidence covers all the main areas, but his evidence on recovery of direct costs is important to reference.

1. Recovery Mechanism
Distribution utilities should be allowed to recover their investments in C&DM programs. The Conservation Working Group has proposed that each utility establish a Conservation Expenditures Variance Account, which would allow for deferral of "the variance between a utility's budgeted annual conservation revenues and expenditures" and associated carrying charges. This Conservation Expenditures Variance Account should actually include only the expenditures that are expensed and the carrying charges on capital investments. Most of the costs of capitalized expenditures will be recovered after the next rate rebalancing, when they will be reflected in the utility's rate base. Compliance would be straightforward, since the utility's spending on C&DM can be determined from accounting records. Explicit incremental C&DM expenditures (rebates, equipment purchases, hiring dedicated staff and contractors) should be easily tracked.

2. Cost-Effectiveness
As part of the cost-recovery process, utilities should be required to demonstrate that their programs are reasonably expected to be cost-effective under the *societal cost test* [emphasis added]. Each large utility may wish to demonstrate the cost-effectiveness of its particular package of C&DM measures and programs. Smaller utilities should be encouraged to make this demonstration by such low-cost approaches as follows: adopting programs in use by other Ontario utilities and previously reviewed by the Board

- adopting programs in use by utilities in other jurisdictions, and subject to cost-effectiveness review in those jurisdictions,
- filing joint proposals with similar or identical programs across a number of small utilities.

A consultative effort, such as the stakeholder advisory group proposed by the CWG to assist the Board's auditor and staff with pre-approval of inputs and with audits of utility revenue claims, should be encouraged to develop avoided costs, design standard programs, and demonstrate the cost-effectiveness of those programs. A single effort of the most-knowledgeable parties, with province-wide effect, would reduce costs, Board Staff time commitments, and redundant efforts by many utilities. I understand that a first cut at avoided costs will be filed by a group of large electric and gas utilities in January 2005. Based on my previous experience with avoided-cost estimates, these values are likely to be controversial; reaching agreement on avoided costs should be one of the first goals of the auditor and advisory group.

3. Spending Levels
Since most Ontario utilities have little experience with operating C&DM programs, they may lack a sense of an appropriate scale for customer-side program spending. Two related questions may arise for a utility manager, in terms of a potential level of customer-side C&DM spending:
1. Would this magnitude of spending represent an excessive rate effect?
2. Is it likely that my utility could prudently spend this much on C&DM?
To reduce these uncertainties, the Board should establish an expenditure level for C&DM that is prima facie reasonable. The following table shows the spending in dollars per MWh on energy efficiency and renewable energy for a number of [US]`utilities.

Table 1: Leading Utility Spending on C&DM (CAN $/MWh)

New Hampshire	$2.2/MWh
*Rhode Island*a	$2.8/MWh
Massachusetts	$3.7/MWh
Vermont	$3.5/MWh
Connecticut	$4.6/MWh
New Jersey	$1.9/MWh
New Jersey	$2.1/MWh
ConEd	$2.0/MWh

Since most of the Ontario distribution companies will be ramping up their C&DM capability over the next few years, and the scope of spending by the Conservation Bureau is not yet known, I recommend that the Board at this time declare that annual C&DM expenditures (including funding from the third tranche) of less than $2.5/MWh of sales are not unreasonable in magnitude. Utilities that wish to spend more than that level on customer-side C&DM should be encouraged to seek review of their plans by the Board or its designee.

5.5 Reply Evidence of Indeco Consultants

The Canadian Energy Efficiency Alliance (CEEA, the Alliance) retained Indeco Consultants who filed reply evidence titled ”Towards Standardization And Simplicity For Aggressive Conservation And Demand Management In 2006:”

Some of the key CEAA conclusions on incentives and standardization of C&DM Programs are excerpted below:

> The three key actions the Alliance supports are:
>
> 1. Establishment of a lost revenue adjustment mechanism and an incentive mechanism for 2006 that sends the right financial and business signals to the utilities to carry out successful, aggressive CDM.
> 2. A mechanism for local distribution companies (LDCs) who have spent their C&DM budgets from the third tranche to apply for inclusion of the costs of conservation and demand management programs in their 2006 rates.
> 3. Establishment of procedures to simplify calculation of incentives and to simplify auditing and evaluation.
>
> **Incentive Mechanisms LRAM and SSM**
>
> With respect to a LRAM for 2006, the following principles are viewed to apply:
>
> 1. It should be straightforward and transparent, and easy to administer.
> 2. It should be prospective, rather than retrospective, i.e. LDCs should estimate load reductions in advance and incorporate these reductions into their rate filings.
> 3. There should be pre-approval of key input assumptions.
>
> LDCs should be encouraged to take into account load reductions anticipated to occur as a result of C&DM initiatives, and thereby keep the LRAM as small as possible. In an ideal world, LDC load forecasts would include the expected impact of their C&DM programs and would be sufficiently accurate that no subsequent adjustment to rates would be necessary. In practice, this may be difficult to achieve, especially in 2006 because of the lack of experience with C&DM and load forecasting that includes C&DM. The methodology chosen for the lost revenue adjustment mechanism for 2006 should lead to small revenue adjustments to the extent possible to minimize rate shock.
>
> Although the lost revenue adjustment mechanism is being set for 2006 only, it would be desirable for it to be developed with minimal change so that it can be applied going forward in a PBR framework beyond 2006. This would enable LDCs to begin to set up

standard systems and approaches for the calculations which would minimize costs. The goal of conservation and demand management programs is to achieve results, not just to spend money and therefore, the incentive should be based on these results. In theory, the results aimed for are those measured by the Societal Cost Test (SCT), which takes into account financial costs and benefits, and non-financial costs and benefits (like environmental externalities). In practice, the evaluation of non-financial costs and benefits is difficult and controversial, and many jurisdictions have chosen to consider only financial costs and benefits, which are measured by the Total Resource Cost (TRC). Another way of measuring results would be in physical energy or power units, such as kilowatt-hours or kilowatts.

The Alliance would find an incentive based on 5% of Total TRC [emphasis added] or a comparable incentive one based on energy units acceptable for 2006.

Pre-approval of key assumptions

The Board can reduce the subjectivity and complexity in the calculation of the LRAM and the incentive in 2006 by encouraging agreement at the start of the C&DM planning process on key variables, rather than doing so once the programs have already been delivered. Where improved data become available, these can be used going forward, but should definitely not be used retroactively.

The Board has already pursued this route somewhat in the regulation of gas utility DSM. For example, agreement was reached on a number of parameters, including measure lives. The Board could designate the Conservation Working Group (CWG), or another group, to propose default values for as many as possible of the variables that go into the incentive calculation for 2006. As a starting point, the CWG may wish to look at California's *Policy manual on energy efficiency,* which was updated in 2003 (CUPC 2003). Key data tables from this document are appended. Some adjustments may be required for application in Ontario. Parameters that might be agreed to in advance of program delivery include:

- Avoided wholesale electricity costs (energy and capacity). Avoided transmission costs (energy and capacity)
- Avoided distribution costs (could develop a provincial average, and allow LDCs to proposed unique costs with supporting evidence)
- The discount rate to be used in net present value calculations
- Unit energy savings from common programs. For example, for a residential compact fluorescent lighting (CFL) program, agreement might be reached that a 13 W CFL could be assumed to replace a 60 W incandescent that operated 3 hours per day, hence saving 51 kWh per year (47 W x 3 h/d x 365 d/a).
- Measure lives. Some measure lives have already been agreed to for gas DSM, and equipment life for numerous types of equipment are given in the California *Energy policy manual*. Others could be calculated. For example, carrying on with the CFL example, assuming an operating life of 5000 hours, the "measure life" for a CFL would be 4.6 years (based on usage of 3 h/d).
- Net to gross ratios. These adjust total (gross savings) for 'free riders'. For example, if the net to gross ratio is 0.75, than total savings are multiplied by 0.75

to get net savings (i.e. savings net of free riders). These ratios are typically program specific, though a default value for non-listed programs may be specified.

- Attribution of program savings. The Minister, in his letter of 31 May 2004 to electric utilities, encouraged the formation of partnerships between LDCs and others to lever incremental investments, and the Board will want to encourage these partnerships. Again, a key consideration for LDCs will be the simplicity of monitoring and reporting results from these partnerships. LDCs can simplify this somewhat by reaching agreement with their partners at the outset on how net benefits will be allocated (particularly where multiple partners will be pursuing incentives, based on these net benefits). Reaching these agreements up-front should be strongly encouraged by the Board, if not required. Where some or all partners are not applying for an incentive based on the net benefit, the LDC should propose what fraction of net benefits it will be seeking credit for (and how this was arrived at), or what methodology the LDC will be using to do the allocation.

Budgeting for Conservation and Demand Management Programs

The Board must identify a mechanism for 2006 for setting a budget for continuing programs that begun under ‘third tranche spending’, or initiating new programs that benefit the utility and their customers, and for recovering those expenditures in rates. Without such a mechanism, LDCs that spend their third tranche dollars early will have no mechanism to continue successful programs or develop new programs based on the experience they gained from their third tranche spending on C&DM. At least three approved plans – those of Brantford Power, Milton Hydro and Brant County Power – anticipate completing their “third-tranche spending” in 2005. In December 2003, the Minister of Energy announced that electricity distribution utilities (LDCs) would be eligible to receive their third tranche of market adjusted rate of return (MARR) provided they invested an amount equal to one year of the incremental distribution revenues stemming from this increase in conservation and demand management initiatives. This “third-tranche spending” for conservation and demand management is to be spent by September 2007.

To this end, the Board has published guidelines, frequently asked questions and procedural orders for LDCs to assist them in preparing plans for these programs, and a number of LDCs have received interim or final approval for their plans

Although the Ontario Power Authority will be gearing up its Conservation Bureau in 2005, there will still be an important role for local distribution utilities in designing and delivering programs that address specific local needs in their service area, or that require direct customer contact. Some of these programs will build on the success of their ‘third-tranche’ programs LDCs who expect to have used up all of the spending on C&DM programs financed through one year of their third tranche before or during 2006 should be eligible for a new C&DM budget for 2006 beyond their third tranche. LDCs that complete or expect to complete their third tranche spending by the end of 2005 should be able to incorporate a C&DM budget for 2006 in their 2006 rate application. LDCs that complete or expect to complete their third tranche spending by the end of 2006 should be

able to obtain approval for a C&DM budget for the remainder of 2006 and track these expenditures in a deferral account for dispensation as part of their 2007 rate filing.
The OEB should specify a standard audit protocol on the evaluation report. The protocol should indicate that the purpose of the audit is to make a determination on whether the claimed amount of the incentive is accurate and appropriate. The LDC would be expected to retain a third party auditor to carry out the audit in accordance with the Board's audit protocol. Since the LDC is responsible for other audits related to its operations, having the LDC responsible for the incentive audit is a reasonable approach. A standard protocol would include the following characteristics: Review of the steps that lead to the incentive calculation. These may include, but are not limited, to:
o Savings per measure
o Number of measures installed
o Number of participants
o Measure costs
o Total program costs

Verification of the accuracy of the data and all calculations. Identification of inconsistencies and errors, as well as assumptions requiring greater support and make recommendations for the future. The LDC will have the opportunity to accept or reject a recommendation with reasons. For 2006 it may be appropriate for all LDCs with approved C&DM plans to carry out an audit of their programs as part of their learning. However, going forward, requiring an annual audit for every program should be reconsidered. This is a costly exercise, especially for LDCs with relatively small (e.g. under $3 M C&DM budgets) even with standard protocols and fixed input assumptions in place. Where annual audits are undertaken, these would not necessarily be comprehensive audits, but rather would be spot checks, as is done for financial analyses. More comprehensive audits could be undertaken where problems are identified or suspected.

5.6 Comparison Of Prescriptions for C&DM Regulatory Framework

The pre-filed and reply evidence and the oral testimony presents the Board with a somewhat confusing array of "solutions" for an appropriate C&DM regulatory framework for 2006 and beyond. Provided below is a table that summarizes the views of the various consultants:

Table 4 Comparison of Proposed C&DM Regulatory Prescriptions

C&DM Regulatory Attribute	LEI	RI	PIE	Indeco	CWG
Targets GWh MWH	Not required	Not required	Not required	Not required	Not Required
2006 Budgets	1-5% of Revenues	\$2.50/MWh ~\$300 m			
Inclusion of 3rd tranche spending	Take into account in setting 2006 Budget		Not Addressed	Include 3rd tranche spending in 2006 Budget	
Cost Recovery	Direct Costs Capitalized	Expensed +Deferral Account	Not Addressed	Maximum capitalization	Distinguish ratebase costs
Standardization	Good Idea	Not Addressed	Not Addressed	Measure life and savings	Highly Desirable
Avoided Cost	Required -Marginal avoided cost	Required	Marginal Cost	Required	Required
Attribution	Protocol Reqd	Protocol Reqd	Split Savings	Split Savings	Split Savings
TRC vs. SCT	TRC	SCT	TRC	TRC	
RIM	Not Required				
LRAM	Load forecast	Load forecast		Load forecast	
SSM	Desirable	For Customer Side C&DM Only 5% sharing	5% of TRC benefit	5% of TRC benefit or based on KWh	5% with sharing
AUDIT	Standard Protocol	Standard Protocol		Standard Protocol Each Utility	Standard Protocol
Stakeholders	Not Addressed	Consultative	Not Addressed	Consultative	Consultative

5.7 VECC submissions on C&DM Regulatory Framework for 2006

VECC is most concerned that Ontario put in place a proper regulatory framework that focuses first on the benefit/cost of C&DM programs to the Province's electrical system, second on benefits to electricity ratepayers and third and last, to the utilities and their shareholders.

The focus of all the evidence to-date has been on the last objective with the reverse logic that if the utilities are incented to undertake C&DM then appropriate C&DM will happen. This ignores the fact that the utilities are **required**, as part of the governments response to the looming crisis of supply/demand imbalance, to undertake Cost-Effective C&DM. By attacking C&DM in this current reverse manner provides no assurances that the programs provided by LDCs will in fact produce demand and energy savings that will be valued in excess of the program costs; which is the mandate of cost-effective programs. The outcome of programs that have not been determined to be cost-effective on the on-set could merely result in program cost that increase electricity rates for customers with no offsetting benefits to customers.

Mr. Goulding of LEI was questioned about the issue of the need for incentives particularly an SSM

MR. WARREN: Now, my conclusion from reading your report, and correct me if I am wrong, sir, I don't see any -- let me take this in bits and pieces. I don't see any survey data in there that would allow -- that speaks to this threshold question of whether or not incentives are needed for LDCs to pursue new CDM programs. Am I correct in that?

286

MR. GOULDING: I think you're absolutely correct. We were not asked to do a survey of various utilities to determine their particular views on whether an incentive was required, that's absolutely correct.

287

MR. WARREN: Well, let me cut to the nub of it, then, sir. Is it fair for me to say that your report proceeds on the assumption that incentives are needed for LDCs to pursue CDM programs?

288

MR. GOULDING: The report proceeds on that assumption, and it is also my belief that such incentives are necessary with regard to this particular initiative.

289

MR. WARREN: That's a fair statement, sir, but if I wanted to understand the basis of that in terms of, for example, a survey of the Ontario LDCs or a survey of the state of play in the United States, none of that is in your report; fair?

290

MR. GOULDING: That is fair. What I would add is that I have participated in the valuation or acquisition of more than 30 distribution wires companies worldwide, and that position gives me a very strong understanding of the behaviour of utility management with regard to the range of activities that they must undertake

Now as to what is an appropriate level of utility expenditure should be and whether this should be on top of the 3rd tranche MBRR spending in 2005, Mr Goulding had this to say:

MR. WARREN: Now, my question combining all of this then, sir, is this: Coming up with a suggestion of 1 percent of revenues as the appropriate number for them, to what extent did you take into consideration the availability of and the use of that third tranche spending by the utilities

R. GOULDING: Well, I think the question is interesting. I must emphasize that our mandate was not to comment on that particular third tranche spending, its appropriateness, the size of it, the effectiveness of it, but rather to look on an ongoing basis, from 2006 onwards. So we were certainly aware of this particular phenomenon, but we were not asked to comment on it, its appropriateness, or to really discuss it in any particular detail.

339

MR. WARREN: That's fair, sir. That is legitimate, certainly, for you to point out that limit, but when you posit, as you do on page 50, a suggestion that 1 percent of revenues is an appropriate number, surely you and I can agree that expending 1 percent of revenues may not be necessary if the LDCs still have a wallet full of money from the third tranche; fair?

340

MR. GOULDING: Well, I think it's -- the kind of absorption capacity is one that should be taken into account. And I think in most of the mechanisms we've talked a bit about looking at total resource cost tests and a host of other issues to try and make sure that spending is, in fact, efficient. Our discussion of the magnitude of spending is, effectively, based on a particular year in isolation, without any particular view of what has come before, as was consistent with my mandate.

VECC disagrees with Mr Goulding's position on incentives. Simply put, incentive payments must be earned by superior performance, not simply a reward as a percentage of the TRC benefit. A sliding scale that rewards <u>superior</u> performance in terms of cost per MWh is required.

- VECC also disagrees with Mr Goulding on whether the third tranche spending on C&DM should be taken into account when deciding an appropriate level of C&DM for 2006. VECC's view is that the Third tranche spending resulted from allowance of utilities to earn their full allowed MBRR in 2005. The programs in 2005 should not be part of the C&DM for 2006 since the current programs are pilot programs, not subject to TRC test or other avoided cost/benefit analysis, and the C&DM in 2005 are not part of a multi year set of C&DM targets.

Nonetheless, except in a few cases where the expenditures were to be made solely during fiscal year 2005, ratepayers will be paying for these programs in 2006. VECC disagrees with Mr. Goulding that the choice for cost/benefit screening is between the TRC and the RIM tests. Both tests should be used, since the TRC test should screen the measures and the RIM test is required to check the rate impact of the portfolio at the rate class or sectoral level.

VECC urges the Board to take steps to protect ratepayers from the impact of 2005 C&DM program expenditures in 2006 by carrying out the following:

- Require that there be full accounting separation of 3rd tranche spending from new money in 2006.
- Require that all 2006 expenditures that are included in the 2006 Revenue Requirement (Residual 3rd tranche and new money) must pass both the TRC Test and on a sectoral basis, the RIM test.
- Require avoided cost calculations and load forecasts.
- Require that multiyear targets be required for all C&DM programs.
- Place limits on total expenditures per MWH of projected energy distributed over the 2006-2010.
- Require targeted programs for low and fixed income consumers, including but not limited to tenants in social/assisted housing.

With respect to the design of the regulatory framework for C&DM for 2006 VECC finds that the LEI Report flies at too high an altitude to be useful as the pathway for a practical Conservation Handbook and Guidelines for 2006.

As an appropriate pathway to a 2006 C&DM Handbook, VECC agrees with much of the regulatory framework solution proposed by Indeco on behalf of the Canadian Energy Efficiency Alliance. Where VECC departs from CEEA is on the following points, as VECC supports:

- Accounting separation of 2005 (3rd tranche) expenditures and benefits
- The requirement for multi year (2006-2010) MWh targets based on avoided cost

- Rigorous TRC screening of all C&DM measures, (customer and utility side)
- Use of RIM as a cut off for all sectoral/rate class portfolios
- Budgets set based on avoided cost and RIM of~1.0
- Sliding scale SSM based on net TRC benefit (5% max). For Customer Side Only
- Special consideration should be given to targeted programs for low and fixed income customers, including but not limited to, social/assisted housing tenants
- Co-delivery and delivery partnerships (gas/electric) should be encouraged
- Leveraging of Federal programs is a priority
- 2006 Conservation Manual and comprehensive OEB Guidelines to Support pre-approval of Second Generation C&DM (Task Force)
- Defined C&DM audit protocol (also to be used for 2005 C&DM)

In addition VECC recommends the following principles for the regulatory framework for C&DM and for a C&DM Handbook and Guidelines for 2006 and beyond:

- The C&DM regulatory framework should be standardized
- The principle program design parameters should be approved up front
- The incentive mechanisms and post audit requirements should be designed to ensure positive benefit/cost to the electricity system and consumers

Standardization

Targets

- Multi year and annual based on % of energy distributed

Budgets

- Established as % of distributed energy (kWh basis) including 2005 and 2006

Program Screening

- All measures meet the Total Resource Cost Test
- All portfolios meet the Rate Impact Measure

Program Assumptions

- Standard measure lives and savings
- Free ridership
- Attribution

Incentives

- LRAM should be based on a load forecast
- SSM Incentives should be based on TRC

Audit

- Audit Protocols should be standard/pre-approved

Approved Up Front

Pre-approval

- C&DM Handbook/Guidelines required
- Task Force with Consulting support

Benefit/ Cost Analysis

- Rigorous Screening of Measures (utility and customer side) using avoided cost, Cost of Conserved Energy and Total Resource Cost Test
- Portfolio analysis and optimization on a per rate class or sectoral basis using Rate Impact Measure Test
- Establishment of Targets (MWh and MW for each utility program for each sector to the years 2010 and 2015

The 2006 CD&M framework VECC has outlined above is one that is more formally and analytically based, and in VECCs view more consistent with the governments desire of implementing a cost effective CD&M Plan that benefits customers. Clearly in order to correctly carry out this CD&M Plan there are a number of standards, pre-approvals, and benefit/cost analysis to be conducted. In the event, the Board is unable from a timing perspective to have this type of rigour established so as it can be correctly implemented for 2006, VECC is of the view the Board should establish for only one-year, a set of interim guidelines for the 2006 CD&M applications. For subsequent years the complete framework as discussed above should be developed in conjunction with the OPA and applied to 2007 and beyond.

PART B COMMENTS AND SUMMARY POSITIONS ON OUTSTANDING/UNRESOLVED ISSUES

CHAPTER	TOPIC AREA	General Comments	VECC Position on Unresolved Issues
1. INTRODUCTION	2006 EDR Model	- Approach should be characterized as "cost of service", either here or in section 3.1	
2. DESCRIPTION OF APPLICATION	Electronic Version	- Models should be filed with the OEB in "working form" – not hard coded.	
3. TEST YEAR AND ADJUSTMENTS	3.0 Test Year and Adjustments	- Treatment/explanation of accounting changes should be identified and discussed in the "Description of Application"	**Issue (p. 16): Need to disclose significant future events** - Applicant should be required to disclose material events for 2006 that are verifiable. (Alternative 1)
	3.1 Historical vs. Future Test Year	No Comments	
	3.2 Test Year Adjustments – Routine Tier 1	- The Handbook needs to be very explicit in that 2005 values can only be substituted for the items identified and, then, only when the 2005 actual value is known and verifiable. - For C&DM and Smart meters, the Handbook should require that Tier 1 adjustments only include: a) Expenses and assets planned for 2006 that are linked to currently approved programs associated with the 3rd tranche of MBRR and b) Any additional spending plans that	**Issue (p. 19): LV/wheeling Adjustments** - Include only those costs/revenues for which an OEB decision has been rendered (Alternative 2). Otherwise could lead to serious inconsistencies between applications and, overall, the Application starts to take the form of a forward test year. Board staff alluded to a number of the problems associated with Alternative 1 in its closing remarks (February 4th, paragraphs 886-890) - In each case some other LDC should be

		are in accordance with guidelines the OEB may approve As recommended elsewhere by VECC, all actual expenses for C&DM or Smart Meters in 2006 rates should be tracked separately and true-up against the allowance for such spending included in 2006 rates. - Handbook should make it clear that retirements applies to assets expected to be retired by start of 2006.	showing offsetting revenues **Issue (Feb 04/05 Transcript, para 880) – Use of Unadjusted 2004 Data** - VECC would be supportive of allowing Applications based strictly on unadjusted 2004 data (i.e., no Tier 1 adjustments at all) provided the Board's approach for Chapter 13 includes variance explanations when overall rate increases exceed an acceptable threshold. **Issue (Feb 04/05 Transcript, para 891) – Treatment of Regulatory Assets** - VECC believes the recovery of Regulatory Assets should not be part of the 2006 Handbook. For most utilities, separate filings are still required to complete the earlier process initiated with respect to regulatory assets and that process should be allowed to continue and reach closure.
	3.2 Test Year Adjustments – Non-Routine Tier 1	- With respect to the OEB staff's concern about disclosure of non-routine costs, this is an issue that can be addressed in part by looking at historical trends and also by the types of variance analyses that could be required in Chapter 13.	**Issue (p. 18&21&26): 2006 I/S TS's** - TS with an I/S date of 2006 should be excluded. The Handbook is not based on the use of a forward test year. (Alternative 2)

			Issue (p. 21-22): Bad Debt Treatment - Do not allow recovery of unusual 2004 bad debt expense. There is a need to define a reasonable allowance for Bad Debt expense. This could be done by adopting a 3 year average of bad debt; i.e., 2002 to 2004.
	3.2 Test Year Adjustments – Tier 2	- There is a need to clarify (page 22) what is meant by second third of MBRR, i.e., is this specifically with reference to the 2002 rate adjustment? - The Handbook should make it clear that this does not apply to LDCs who did not apply/receive full MBRR for 2005. - The Handbook should emphasize that "need" for funds must be demonstrated	**Issue (pp. 23 & 28): Allowance for Catch-Up Adjustments** - Adopt Alternative #2 and allow for corrective action. However, there's a need to recognize that funding of corrective action may need to be spread over more than one year in order to reduce rate impacts.
4. RATE BASE	4.1 Definition of Rate Base	- It is not clear as to when the Handbook is referring to Schedules in the main text vs. Appendices - There does not appear to be any provision for LDCs who own/operate TS's – are these assets to be included in rate base? (Note – VECC believes they should be allowed provided they are not included elsewhere for rate recover - Need to emphasize that p. 31 adjustments are for actual known costs	**Issue (p. 30): Definition of Rate Base** - VECC supports end of 2004 for Tier 1, but only because 2006 uses a historic test year. Normally the average should be used for forward test year.
	4.2 Amortization	No Comments	
	4.3 Capital Investments	- LDCs should be required to file Capital Expenditures for years prior to	**Issue (p. 32): Non-IT Materiality**

		2004; i.e., 2002 and 2003 should also be filed. - IT limit for rate bases over $1 B should be lowered to $300 k	-Adopt a $ value for materiality as well as a percentage for rate bases over $1 B.
	4.4 Interest on Deferral Accounts and CWIP		**Issue (p. 34): Interest on Deferral Accounts and CWIP** - Adopt Recommendations of Mr. Matwichuk. See Main Argument
	4.5 Capitalization Policy		**Issue (p. 34): Filing of Capitalization Policy** - Require provision of capitalization policy (Alternative 2). This will help inform the OEB as to where there is a need for more specific direction to be provided to LDCs on capitalization policy.
5. COST OF CAPITAL	5.0 Introduction	No Comments	
	5.1 Maximum return on equity	No Comments	**Issue (p. 39): ROE and Debt Rate** - Set ROE and Debt Rate based on values as when Handbook is issued (Alternative 1). The OEB could consider requiring LDCs that revise their applications/file at a later date to use a more updated value. Do not introduce deferral accounts – an unnecessary complication
	5.2 Debt Rate	No Comments	**Issue (p. 41): Basis for Deemed Debt Rate** - Use Alternative 2. This approach is fairly easy to implement (i.e., OEB will simply need to create a schedule of historical

			deemed rates that change on a regular (e.g., quarterly) basis) and it is fairer to both LDCs and customers.
	5.3 Capital Structure	No Comments	
	5.4 Working capital allowance		**Issue (p. 43) – COP Treatment** - Adopt Alternative #4 – where COP is based on 2004 values. This approach is consistent with the philosophy of the Handbook, which is to rely on actual costs not forecasts. **Issue (p. 44): Security Deposits** - If the interest expense for the Security Deposits is allowed as an expense in the revenue requirement, then the working capital allowance should be reduced to avoid double counting of this cost to the LDC. **Issue (p. 45): Weighted Average Debt Rate** - Reject both alternatives offered – see page 41 comments above and adopt consistent approach
6. DISTRIBUTION EXPENSES	6.0 Introduction	- In their closing comments (paragraphs 924-935) Board staff raised a number of issues and requested comment: a) Interrogatories vs. Filing (para. 927) – The two are not directly comparable. Parties must formally intervene in order	**Issue (p. 47): Level of Detail Required** - Not clear what level of detail would be provided under Alternative #2. Level of disclosure in Appendix – Table B.2 (page 165) is reasonable

		to ask for interrogatories. Providing more information upfront may reduce the number of interventions and shorten/simplify the overall process b) Presumption of Scrutiny (para/ 927) – The information in question is all provided to the OEB as part of the LDCs' RRR filings. As a result, a presumption of scrutiny already exists. c) Transparency (para 931) – One of the reasons this is an issue of significance is that the Board has deemed the LDC RRR filings on expenses as "confidential" – meaning the annual rate review is the only opportunity customers and stakeholders have to gain access to such information.	
	6.1 Definition of Distribution Expenses	No Comments	
i	6.2 Detail of Reporting	**-** Board Staff (Feb 04/05, para. 941-946) invited parties to comment on the approach the OEB should adopt with respect to Affiliate Transactions. VECC is of the view that: a) At a minimum the OEB's Rates Panel needs to confirm that material affiliate transactions are being "priced" in a manner consistent with the Affiliate Relations Code if it is to satisfy itself that rates for 2006 are just and reasonable. b) The 2006 EDR Process offers the OEB an opportunity to gain insight into	**Issue (p. 49): Self-insurance** - Adopt Alternative 1, but only if concrete reserve policy in place for start of 2004 and formal documentation is provided as part of the filing. **Issue (Feb 04/04 Transcript para 937 / page 50): Advertising** - VECC supports Board Staff's suggested wording change

		how the Affiliate Relations Code is being applied by the various LDCs and therefore whether a more detailed investigation by an audit or compliance functions is warranted.	**Issue (p. 51): Charitable Contributions** - Adopt Alternative 1. However, the OEB should consider instituting a "cap" on the level of allowable contribution based on a % of actual 2004 net income. There is also a need for the LDC to address the issue of donations "in kind" (e.g., provision of services as opposed to cash). **Issue (p. 52): Meals and Travel** - VECC supports filing of meals and employee expenses policies. This requirement is consistent with what should be a broader OEB objective of having LDCs formally document their management practices. Staff's suggestion that this info could be provided through interrogatories. However parties seeking this type of information then would need to formally intervene in the LDC application, thus negatively impacting the regulatory process. **Issue (p. 54): Compensation – Minimum Filing Requirements** - Initial references to 3 FTE's should be changed to 3 employees, which may be less than 3 FTE's. Adopt Alternative #1 – change the requirement to $100,000 per

			FTE (i.e., an employee working ½ time an earning $60,000 would not meet the criteria). **Issue (p. 55): Compensation – Additional Filing Requirements** - Adopt Alternative #2 where disclosure does not create legal problems. If average compensation raises questions Board can pursue. **Issue (p. 55) – Incentive Plans** - VECC supports Alternative #2. Without details of incentive plans, the OEB will not be in a position to apply either alternative. Handbook should flag specific requirement to separate out illegible amounts for 2004**.** **Issue (p. 58) - Affiliate Dealings – Additional Filing Requirements** - VECC supports the use of Alternative #1 – but only for material transactions above a defined materiality limit (e.g., 0.2% of total distribution expenses – same limit as used to define, materiality of unusual 2004 expenses**.** **Issue (p. 58) - Affiliate Dealings – Additional Wording**

			Support Alternative 1 or variation thereof. The issue of dealings with affiliates and how they are priced is something that should be addressed in the overall Description of the Application (Chapter 2).
7. TAXES	7.1 Rules and Principles	- The Board may wish to consider whether updates to the Handbook for "tax changes" (page 68) could also be used as an opportunity to update the ROE section as well (based on more recent interest rate forecasts and spread data)	**Issue (p. 69): True-Up for 2006 Actuals** - Allow true-up for tax policy, law and reassessment changes only - Alternative #1 – share. **Issue (p. 72): Taxes savings on disallowed expenses** - No Position **Issue (p. 73): ECE for Fair MV Adjustments** - No Position **Issue (p. 73): ECE for disallowed expense** - No Position **Issue (p. 74): Charitable expenses** - No Position **Issue (p. 76): Sharing of LCT exemption** - VECC supports the current approach as set

			out under (iii) as opposed to the alternative provided. **Issue (p. 77): Treatment of FMV Bump** - No Position **Issue (p. 78): Interest Deductions** - Alternative 2 not appropriate. Should not single out interest deductions as the sole item to be based on what will occur in 2006. Otherwise – no position. **Issue (p. 83): Future Disclosure** - VECC believes there should a requirement for LDCs to disclose actual taxes paid even if there is not a separate tax return for the distribution business
8. REVENUE REQUIREMENT	8.0 Introduction & 8.1 Service RR	- No Comments	
	8.2 Service Revenue and Base Revenue	- The Tier 1 revenue adjustment for LV should only include charges that have been approved by the OEB for 2005. The treatment of LV revenues needs to be consistent with the treatment of costs as per section 3.2. - Would be useful to have a history of revenues from LPC and miscellaneous charges.	

	8.3 C&DM, Smart Meters and amort. of Regulatory Assets	- As Board staff has noted the "allocation of C&DM and Smart Meters" is not yet determined (para. 962). VECC believes that – given the potential future materiality of these costs – their allocation treatment must be determined as part of the upcoming "Cost Allocation" review – where their treatment can be given the level of consideration they should merit.	
9. COST ALLOCATION	9.0 Introduction and 9.1 Customer Classes	- The reference on page 93 to "existing practice" is rather oblique and open to interpretation. The OEB should clarify what it considers the existing practice to be or, in the alternative, LDCs should be required to say what their practice is. This would prevent other situations like that of scattered and non-metered loads arising	
	9.2 Allocation of RR to Classes	- The Handbook (page 94) currently allows for load adjustments due to C&DM and Smart Metering impacts. Consistent with the requirement for Tier 1 type adjustments, such adjustments should be permitted only if the impacts are clearly identifiable and verifiable (i.e., based unit savings that have been verified and committed to the programs). There should also be materiality limits – similar to those imposed for customers losses - before any such adjustments are made - In the case of Smart Meters, it will be	**Issue (Feb 04/05, Transcript para. 968 / page 93) Materiality for Loss of Major Customer** - VECC agrees that a materiality criteria is required with respect to a known/verifiable loss or gain of a major customer during/after 2004. VECC would suggest that 5% threshold would be reasonable – recognizing that load growth will to some extent offset the impact of customer losses.

		important to distinguish between load shifting and load reductions, as the former will not have the same impact on distribution revenues.	
	9.3 CDM/SM/RA Allocation	- In the case of Regulatory Assets (page 95), rather than having each LDC determine the allocation treatment based on the OEB decisions – it would be useful if the OEB were to specify (in the Handbook) the allocation treatment required based on its December 2004 Decision.	**Issue (Feb 04/05, Transcript para. 969 / page 94) – C&DM and Smart Meter Allocation** - SM and CDM need to be addressed as part of the upcoming cost allocation work. Inappropriate to make LT decisions on these topics without full review. For 2006, allocation should be based on same as that for other costs,
10. RATES AND CHARGES	10.0 Introduction	No Comments	
	10.1 Fixed/Variable Split	- It is not clear from the text what are the "distribution base rates" are defined to be; i.e., 2005 rates or 2004? This issue has taken on increased importance since the OEB's RAM for 2005 has lead to a change in then F/V split for 2005vs. 2004. It is VECC's view that, in order to minimize impacts, the 2005 rates and the underlying F/V split should be used as the "base rates" in determining the F/V split for each class. To do otherwise, creates unnecessary bill impacts that could require mitigation. - The OEB's December 2004 Decision on Regulatory Assets did not specifically address the issue of rate design. The Board should specify how it intended the regulatory assets to be recovered in rates	

		through the rate design, or direct LDCs to allocate regulatory assets on a "default basis"	
	10.2 Unmetered and Scatter Load	- VECC supports the approach as outline in the Handbook, but only as an interim/one year solution.	
	10.3 TOU Rates and 10.4 Tx Ownership Allowance	No Comments	
	10.5 Loss Factor Update		**Issue (p. 105): Loss Factor Update** - VECC supports Alternative 2 as it incents LDCs to reduce losses.
	10.6 Distributed Generation (DG)		**Issue (105): Should some form of interim measure be adopted to encourage DG** - VECC supports the implementation of an interim measure (Alternative #2) **Issue (p. 106): Sharing** - VECC supports Alternative #2-b – 50/50 sharing. It takes the existence of both the DG and the LDC to create the benefit that suggests sharing is appropriate. **Issue (p. 106) – Admin Fee –.** - VECC supports "will" (Alternative 2-c) if no sharing. However, "may" (Alternative 2 d) would be acceptable if there is sharing.

	10.7 Stand By Charges	- The Stand By charge should only be dropped entirely (page 107) if revenue from normal use more than offsets it.	**Issue (Feb 04/05, Transcript para. 992 / page 107): Relation to Net Metering** - VECC believes the issue of net metering relates to commodity and transmission costs, while standby applies to distribution costs. As a result, the two are distinct. **Issue (Feb 04/05, Transcript para. 985 / page 94): Relation to RP-1999-0044** - The RP-1999-0044 findings were for all Tx customers. Fixed charges already exist for Distribution customers. To suggest they shouldn't apply would be fundamental policy change and should not be made at the 11th hour as part of the 2006 EDR process. Indeed, if applied here the same approach should be adopted for other customers and the monthly fixed service charges should be eliminated. - If the OEB is concerned this should be dealt with as part of the Cost Allocation review. Also, stand-by charges are not "fixed" (as a customer charge is) but rather set based on the connected load – which varies by customer.

	10.8 Low Voltage Charges	- VECC notes that the asset classes used to report costs in Schedule 10-8 don't match those used for rate base or for DX expense details. LDCs will likely need more direction in terms of how to complete the table, particularly if the details required are not part of the OEB's standard USOA requirements. - Presumably after the host LDCs have done 10-8, then the embedded LDCs will be able to determine what to recover. Handbook needs to outline how this iterative process will work. Also – each host LDC should be required to ID and notify its embedded LDCs.	
	10.9 Demand Determinants	- Need to clarify that the use of 100% kVa applies only if current (2005) rates approved is using this determinant.	
	10.10 CDM/SM/RA	- See earlier comments regarding sections 9.3 and 10.1	
11. SPECIFIC SERVICE CHARGES	11.1 – 11.7	- All Formula based charges that are materially different (i.e., 10%) from those currently approved should be supported by a variance analysis that explains the basis for the change.	**Issue (Feb 04/05, Transcript para. 995): After Hours** - It may be impractical for the Handbook to specify what "after hours" are for all LDCs. However, as a matter of principle there should be at least 40 hours per week where service is available at the standard price and LDCs should be required to specify in their Applications what these are. Also, charges for after hours should be limited to

			instances where the customer requests "after hours" service. Emergencies related to safety or reliability should not be billed at higher after hours rates. **Issue (Feb 04/05, Transcript para. 996): Power Quality Inspection** - There should be no charges for power quality inspection, unless the problem is one caused by the customer and is the customer's responsibility to resolve.
12. OTHER REGULATED CHARGES	12.2 Retail Service Charges	- VECC is concerned that many of the Retail Service charges are not cost based and objects to the wording in the Handbook, which suggests they are. This issue is compounded by the OEB's Decision last December to not clear the variance accounts associated with these charges to retailers – but rather to charge the variances to all customers, including those on Standard Supply. At a minimum, the Board should commit to having these charges reviewed as part of the upcoming Cost Allocation review.	
	RCVA 12.3 Non-Competitive Electricity charges	No Comments	
13.Mitigation	13.1 Impact Analyses 13.2 Mitigation Methodologies	See the detailed Argument on this issue with respect to evidence provided by ECS and PA Group	

14 Comparators and Cohorts	14.1 Methodology 14.2 Filing Requirements	See detailed Argument on Camfield and Lowry Evidence	
15.Service Quality Regulation	15.1 Customer Service Performance Indicators (CSPI) 15.2 Service Reliability Indices (SRI) 15.3 Cause of Service Interruption	- VECC supports the proposed filing requirements which includes reporting historic performance. The filing should also require each LDC to provide its original "targets" based on the 2000 Handbook. -VECC is also of the view that LDCs should be required to provide a self-analysis (variance analysis) for any of the Performance Indicators that are exhibiting worsening trends. Such analysis would be consistent with what participants would expect to see during a standard cost of service review. - Finally, LDCs should be expected to discuss their remedial action plans if they to fail to meet CSPI or SRI targets.	

C&DM ISSUES		
ISSUE	**Evidence**	**VECC Position(s) – Summary of Detail Argument in Part A**
Regulatory Framework	Working Group Report	C&DM Handbook/Filing Guidelines Separate 3rd Tranche C&DM
Regulatory and Accounting Treatment of C&DM TRC & RIM Tests	LE Page 6	Expenses should be expensed except where Utility owns asset. Targets are required against which to judge performance. All Measures should be subject to TRC test and portfolios for each rate class must meet RIM of 1. Utility side programs should meet RIM=1
Lost Revenue Adjustment Mechanisms	LE page 15	For Tier 1 LRAM should be based on 2004 energy delivered (including line losses). A PBC of x mil/kwh will simplify regulatory oversight For 2006 Forward test year- load forecast required. In future prospective test year should be used with true-up.
Shareholder Incentive Mechanisms	LE Page 20	SSM should be used and include 50:50 shareholder/ratepayer split above target. Alternative Bonus to shareholder based on 2.5 % of TRC benefit
Loss factor Incentive Mechanisms	LE Page 31	Should be based on line loss factor used for rates-3.6% on average Could use the Cost driver from C&C
Ontario Market Structure	LE Page 38	Corporate and territorial heterogeneity. Role of OPA Conservation Bureau
Prototype C&DM models	LE Page 42	Model 2 Preferred
Standardization	Can Energy Efficiency Alliance	Support Standard Framework- allow for some exceptions based on Application Support Standard Measure savings and life
Avoided Cost		System wide avoided cost for Generation (RPP) and transmission (pool rate) Distribution use average or provide study to justify higher.
Universality		All customers that pay for C&DM in rates should have access to programs
Low/Fixed Income Customers		Low/Fixed Income customers should have access to Social Housing and LI programs for utilities
Cost Allocation/ Rate Design Treatment	Should this be revisited as part of 2007 cost allocation	If Class RIM adopted then this may be acceptable to allocate directly to classes and recover based on energy portion of rate structure. Otherwise – total costs to all customer classes based on energy.