Ontario Energy Board | Commission de l'énergie de l'Ontario

DRAFT GUIDELINES FOR

ELECTRICITY DISTRIBUTOR

CONSERVATION AND DEMAND MANAGEMENT

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OVERVIEW

1.0 PURPOSE

The draft Guidelines for Electricity Distributor Conservation and Demand Management (the "Guidelines") provides comprehensive information on the Ontario Energy Board's (the "Board") policies and requirements relating to conservation and demand management ("CDM") activities undertaken by electricity distributors in Ontario. The policies set out in this document are intended to guide distributors in designing program proposals, applying to the Board for funding, and implementing their programs.

In its March 2, 2007 "Report of the Board on the Regulatory Framework for Conservation and Demand Management by Ontario Electricity Distributors in 2007 and Beyond" (the "Framework Report") the Board confirmed its ongoing role in CDM activities by electricity distributors through the review and approval of spending levels and proposed programs, reporting guidelines, program evaluation, and the review and approval of applications for recovery of the Lost Revenue Adjustment Mechanism (LRAM) and the Shared Savings Mechanism (SSM). The Board also reviews and approves claims for LRAM recovery associated with distributor CDM activities that are funded by the Ontario Power Authority (the "OPA").

Given this continued role, the Board believes it is important to provide its policies and guidelines on all aspects of CDM for electricity distributors that are within the scope of the Board's oversight on this issue.

With the exception of four new issues identified below, the draft Guidelines are a compilation of existing Board policies and guidelines that are currently set out and/or confirmed in the following documents:

- Report of the Board on the Regulatory Framework for Conservation and Demand Management by Ontario Electricity Distributors in 2007 and Beyond;
- Total Resource Cost (TRC) Guide;
- Filing Requirements for Transmission and Distribution Applications; and,
- Board decisions.

The draft Guidelines address four new policy issues, as follows:

- funding for system improvement programs (section 2.1.1);
- availability of multi-year funding (section 2.2);
- inclusion of distribution and transmission losses in savings calculations (section 3.4.4);
- enhanced evaluation planning and reporting (sections 7.1, 7.3 and 7.4).

With the exception of applications for LRAM recovery associated with OPA-funded CDM activities, the policies set out in the draft Guidelines apply only to CDM programs that are funded through distribution rates. Further, unless otherwise indicated, the policies set out in the draft Guidelines apply to all distribution-rate funded CDM activities, whether relating to the third installment of distributors' incremental market adjusted revenue requirement, or through distribution rates approved in 2006 and beyond.

The Board expects that its policies will evolve over time, and the draft Guidelines will be updated accordingly.

1.1 Background and Introduction

On May 31, 2004, the Minister of Energy granted approval to all distributors in Ontario to apply to the Board for an increase in their 2005 rates by way of the third installment of their incremental market adjusted revenue requirement ("MARR"). This approval was conditional upon a commitment to reinvest in CDM an equivalent of one year's return. Consequently, in 2005 distributors brought forward, and the Board approved, $163 million in CDM funding for distributors, an amount related to the third tranche of their MARR ("third tranche funding").

The Board subsequently provided processes for distributors to apply for additional funding as part of the 2006 and 2007 distribution rate adjustment processes.

1.1.1 The Framework Report

The March 2, 2007 Framework Report addressed the Board's policies in respect of: sources of CDM funding, revenue protection, incentive mechanisms, cost allocation, revenue allocation, program evaluation, and program reporting requirements.

1.1.2 The Total Resource Cost Guide

In September 2005, the Board issued the Total Resource Cost ("TRC") Guide (the "TRC Guide") to assist distributors in meeting the filing requirements for 2005 and 2006 CDM plans approved by the Board. As part of their annual reports on 2005 and 2006 CDM spending, and as part of any application for incremental 2006 CDM spending, distributors were required to provide a benefit-cost analysis of their CDM activities. The TRC Guide outlines the required analysis and techniques for distributors to use when completing the benefit-cost analysis.

Much of the information in the TRC Guide has now been incorporated into the draft Guidelines. However, some information has been retained in the TRC Guide, which is attached as Appendix A to the draft Guidelines. In addition to removing information that is now contained in the draft Guidelines, the TRC Guide has also been revised to include new and more detailed examples of how to undertake a benefit-cost analysis at the measure, program and portfolio level. The tables of Avoided Costs and Assumptions and Measures have also been removed from the TRC Guide, and will be posted as separate documents on the Board's website, to facilitate future updates.

1.1.3 Filing Requirements

In November 2006, the Board issued its "Filing Requirements for Transmission and Distribution Applications", which sets out the Board's expectations in relation to various applications that might be filed by electricity transmitters and distributors. Chapter 6 of that document is devoted to applications for CDM funding through 2007 distribution rates, and for LRAM and SSM recovery.

Section 9.0 of the draft Guidelines contain revised filing guidelines relating to CDM. These supersede those set out in Chapter 6 of the "Filing Requirements for Transmission and Distribution Applications".

1.1.4 Stakeholder Consultations on Regulatory Barriers to CDM

Throughout April and May 2007, Board staff held a number of meetings across the province to discuss CDM and, in particular, regulatory barriers to CDM. The purpose of the meetings was to provide information about the Board's regulatory framework for CDM, and to consult further with stakeholders to identify if there were remaining regulatory barriers within the control of the Board that needed to be addressed.

The discussions at each of the stakeholder meetings generally focused on a need to clarify the regulatory rules applicable to electricity distributors in relation to their CDM activities, relating to both existing and future funding through distribution rates. Stakeholders' comments also suggested that greater clarity was needed in relation to the Board's application and review processes relating to CDM activities, to ongoing and future sources of CDM funding, and to the role of distributors in CDM. The discussions indicated that further clarification was required from not only the Board, but also from the OPA and the Government as a whole.

A Board staff report was issued on July 27, 2007 summarizing the issues raised at the meetings. One of the objectives of the draft Guidelines is to provide greater clarity in areas that have been identified as being in need of clarification.

THE POLICY FRAMEWORK

2.0 FUNDING OF CDM PROGRAMS

There are two streams of funding available to distributors for the delivery of CDM programs: funding from the OPA, and funding through distribution rates. The draft Guidelines discuss the funding available through distribution rates.

2.1 Funding Through Distribution Rates

The Board expects that most CDM funding for distributors will be provided by the OPA, either through the three-year fund of up to $400 million that was introduced by the government through the directive to the OPA on July 13, 2006[1], or through other OPA initiatives. In 2007, the OPA provided funding to distributors for four standard programs.[2] It is expected that funding will also be available from the OPA in 2008 for a selected group of standard programs.

The Board recognizes, however, that additional conservation resources could be provided by electricity distributors with continued funding through distribution rates.

Funding through distribution rates will continue to be available for programs designed to address local reliability situations, or other programs for which no OPA funding is available. As funding from the OPA becomes available for programs that were not previously funded, the Board expects that distributors will apply to the OPA for funding. However, where funding is not available from the OPA at the time of application, distributors may apply to the Board for funding through distribution rates.

In all cases, programs funded through distribution rates must be targeted to consumers within the distributor's licensed service area.

The following sections provide additional guidelines specific to two types of programs: system improvement programs and pilot programs.

2.1.1 System Improvement Programs (New)

In the Framework Report, the Board indicated that it would continue to receive applications for funding through distribution rates for programs designed to address

[1] The directive issued to the OPA on July 13, 2006 instructed the OPA to organize the delivery and funding of CDM programs through Ontario distributors, and established a three-year fund of up to $400 million.
[2] Appliance Retirement, Business Incentive, Summer Savings, and Residential and Small Commercial Demand Response.

system improvement situations. As part of the 2007 distribution rate adjustment process, three distributors[3] brought forward applications for programs to improve the efficiency of the distributor's distribution system. These programs involved the installation of equipment that was more efficient than what the distributor would normally install as part of its capital replacement program. In its decisions on these applications, the Board noted that it may be appropriate to consider programs aimed at improving the efficiency of a distributor's distribution system in relation to their coincidence with the distributor's normal asset lifecycle replacement program.

The Board notes that there are no efficiency standards for distribution infrastructure, and as such, it is difficult to determine what component of a capital project could be characterized as "CDM". Further, the Board is of the view that maximizing efficiency of the distribution system should be part of prudent asset management practices, and not considered "extra" or "optional".

In the case of new infrastructure, or replacement of existing infrastructure, any measures to maximize the efficiency of the infrastructure will not be considered a CDM initiative. The Board expects that distributors will consider energy conservation and efficiency improvements as part of distributors' overall analysis of any infrastructure investment.

The Board is of the view that such an approach will better support conservation in Ontario.

Further, the Board notes that the development of appropriate distributor asset management practices is part of its draft 2008-2011 Business Plan, which will provide an opportunity to further explore the role of energy efficiency in asset management planning.

2.1.2 Pilot Programs

The Board considers a pilot program to be a program that involves the installation, testing or evaluation of technologies that are not already in use in Ontario, or in limited use, and that serves as a tentative model for future development.

The Board expects that a properly structured pilot should provide an opportunity to gain experience in business processes, installation procedures, logistics, deployment, integration issues, customer communications, and customer impacts. A distributor should provide a rationale for how its program will increase the collective understanding of the technology and its benefits as a CDM measure. Distributors should also be prepared to share the results and knowledge gained through the pilot with the Board and other distributors.

[3] The distributors are: Chatham-Kent Hydro Inc. (EB-2007-0517/EB-2007-0109), Middlesex Power Distribution Corp. (EB-2007-0553/EB-2007-0110) and Lakefront Utilities Inc. (EB-2007-0550/EB-2007-0106).

Pilot programs involving smart metering, smart sub-metering and/or time of use pricing are subject to other legal and regulatory requirements that apply in addition to the provisions of these draft Guidelines.

2.2 Funding Term (New)

Electricity distributors in Ontario have had experience with multi-year funding through third tranche funding. Through the 2005 rate-setting process, distributors received approval to spend funds for CDM programs that would cover the period from 2005 to September 30, 2007. Some distributors have since received approval to extend the period of spending beyond September 30, 2007. Distributors were also permitted to apply for incremental funding through 2006 and 2007 distribution rates, although this funding was for a one-year term only.

Multi-year funding has become more common in North America in both the electricity and natural gas sectors. In Ontario, the Board recently approved three-year plans for Union Gas and Enbridge Gas Distribution as part of the Generic Demand Side Management Proceeding (EB-2006-0021) ("Generic DSM proceeding").

There are many benefits to multi-year funding. Multi-year funding can reduce the year-over-year uncertainty regarding budget and program continuity that often comes with funding on a year-by-year basis. It may allow distributors to better plan and manage the resources needed to deliver CDM programs, for example, by hiring full-time staff dedicated to CDM. Given the longer-term horizon, distributors may also have greater opportunity to monitor the success of programs, and make appropriate improvements. Providing a more certain and longer term stream of funding may allow a more strategic approach to program planning, and the implementation of a portfolio of programs with differing lengths.

Multi-year funding can more closely match the requirements of customers, especially commercial and industrial customers. These customers often must first go through their internal management approval processes before enrolling in a distributor's CDM program. In cases where those business cycles are not coincident with the distributor's CDM funding cycle, the distributor may have ended the program and/or exhausted its funding for the program before the customer has the necessary approval to participate. In addition, significant capital spending by distributors may be required to provide CDM programs to the commercial and industrial sectors.

There are also benefits and economies of scale to be found by delivering programs in partnership with other delivery agents. For example, an electricity distributor could partner with a natural gas utility to more effectively target customers whose homes or businesses are fuelled by both electricity and natural gas. Similarly, an electricity distributor could partner with a local community agency to target certain customers. By allowing for a funding term of multiple years, distributors may have more opportunities to partner with other delivery agents, since the distributor would be able to make a longer-term commitment to the arrangements.

Distributors may apply to the Board for funding for a period of up to three years. However, budgets will still need to be developed and measured on an annual basis within the multi-year plan. Annual budget amounts will be an input to each year's distribution rate adjustment. Distributors may apply for recovery of LRAM and SSM at the end of the approved plan term.

Distributors will be required to submit a CDM plan, budget and evaluation plan[4] to the Board for review and approval. Intervenors will have an opportunity to comment on the CDM plan, budget and evaluation plan.

Annual reports will also continue to be required, as described in section 8.0 of the draft Guidelines.

Spending will be tracked in a variance account, which will be used to "true-up" any variances between the spending estimate built into rates for the year and the actual spending in that year. It is expected that distributors will spend each year's annual budget in that year. However, there may be situations where this is not possible, for example, where customer uptake of the program has been slow. For plans with approved spending of more than one year, unspent funds can be carried over to a subsequent year. At the end of the approved funding term, any unspent funds will be returned to ratepayers through rates.

It is also possible that programs may be more successful than expected, such that the annual budget is insufficient. In this case, distributors may bring forward an application, with appropriate evidence and rationale, for recovery in rates of the amount spent in excess of the approved budget.

The additional spending may only be used for incremental program expenses. In order to recover these amounts in rates in a following year, distributors will be required to provide appropriate evidence demonstrating the prudence and cost effectiveness of the amounts spent in excess of the approved annual budget. This is consistent with the model used for gas utilities, as set out in the Board's Decision, dated August 25, 2006, on Phase I of the Generic DSM Proceeding.

[4] The Board's guidelines for an evaluation plan are set out in section 7.1 of the Guidelines.

3.0 COST EFFECTIVENESS

Section 3.0 of the draft Guidelines are substantially the same as that previously set out in section 1 of the TRC Guide, with the exception of section 2.4.4 which addresses distribution and transmission losses.

The Board has adopted the Total Resource Cost ("TRC") test as the appropriate test to measure cost effectiveness, and this test should be used by distributors when evaluating the cost effectiveness of CDM initiatives. The TRC test is defined as a test that "measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participant's and the [distributor's] costs".[5]

The TRC test measures the benefits and costs of CDM efforts from a societal perspective. Under the TRC test, benefits are driven by avoided resource costs, which are the marginal costs that are avoided by not producing and delivering the next unit of energy to the customer. Marginal costs (or avoided costs) include energy, generation, transmission and distribution costs. They measure the expected change in the systems total costs due to a decrease or increase in load and are calculated using either a short-run or long run perspective.

Costs in the TRC test are the costs of any equipment and program support costs associated with delivering that equipment to the marketplace.

Benefits	**Costs**[6]
Avoided electrical supply costs	Equipment costs
Other avoided resource costs	Distributor program costs

3.1 TRC Calculation

Evaluating the cost effectiveness of CDM is done in stages at many different levels, including technology or measure, program, and portfolio. The TRC tests should be performed at each level.

At the most detailed level, a TRC test should be performed to evaluate the cost effectiveness of a measure or technology. Once a technology has proven to be cost effective, a program can be designed using that technology.[7] Once the program costs have been assessed, the TRC test will be performed again to evaluate the cost effectiveness of the program. Finally, several programs are bundled together, further indirect costs are included and the TRC test is carried out once again to evaluate the

[5] California Public Utilities Commission. (2001) Standard Practice Manual: Economic Analysis of Demand-Side Management Programs and Projects.
[6] In the case of fuel switching measures, the costs of the other fuels must be included.
[7] A distributor may deliver programs on non-cost effective technologies in the form of pilot programs or test efforts, as set out in section 2.1.2 of the Guidelines.

cost effectiveness of the portfolio. This three layered structure; technology or measure, program and portfolio, is key to performing TRC analyses.

The results of the TRC test should be expressed as a net present value (NPV). As a NPV assessment, the TRC test sums the streams of benefits and costs over the lifetime of the equipment/technology and uses a discount rate to express these streams as a single "current year" value.[8] Thus, the NPV_{TRC} is the net discounted value of the benefits and costs over a specified period of time (usually dictated by the equipment life of the CDM technology).

The TRC test is a measure of the change in the total resource costs to society, excluding externalities, of the CDM program. If the NPV_{TRC} is positive, indicating that benefits exceed costs, the program is considered cost effective from a societal perspective.

The TRC test examines streams of benefits and costs and uses discounting principles to express these future values as a single number.[9] The benefits stem from the avoided resource costs, typically electricity. The costs are the cost of the equipment and the distributor program costs. Subtracting the costs from the benefits provides the net benefits. For a program to be considered cost effective, the net benefits should be greater than zero.

3.2 TRC Benefits

3.2.1 Avoided Costs

As noted above, the TRC test assesses CDM costs and benefits from a societal perspective. The benefits are defined as "avoided costs". This represents the benefit to society of not having to provide an extra unit of supply – typically expressed as kW and/or kWh. For electricity, supply costs include energy, and generation, transmission and distribution capacity.

Certain CDM programs may have other benefits, including savings of other energy sources and/or water savings. While these savings are not the primary target of the program, the TRC test will accommodate an assessment of savings associated with avoiding the use of other resources including natural gas, heating fuel oil, propane or water. In these cases, the benefits accrue from the avoided costs associated with these resources. Distributors wishing to assess resource savings relating to other energy forms or water will need to use avoided cost estimates for those resources in the same manner that electricity avoided costs are used.

The TRC test requires an analysis over the life-cycle of the CDM measure. To accommodate this, long-term projections of avoided costs are required. Also, any CDM

[8] Discounting is a standard accounting principle which converts future monetary values into current values.
[9] The formula for this calculation is provided in Appendix A.

measures included in the analysis should have equipment life estimates along with estimates of savings and costs.

Not all of the avoided cost components and sub-components will be relevant for evaluating a particular CDM measure or program. For example, a program designed to shift load during peak hours may have little impact on annual energy use. Each potential CDM measure or program should be examined carefully to determine which types of loads will be avoided and which avoided costs apply.

Estimating the electrical avoided costs applicable to each customer class requires a number of analytical steps:

1. estimate marginal generation costs of capacity and energy;
2. estimate marginal transmission costs;
3. estimate marginal distribution costs;
4. determine the appropriate costing periods; and
5. attribute marginal costs to the costing periods.

Marginal cost studies typically involve detailed analyses starting with an understanding of the current costs for generation, transmission and distribution. Capacity costs accommodate the costs of building and maintaining new generating plants and new transmission and distribution systems to meet increases in peak demand. Energy costs measure the additional fuel and variable operating costs required to produce an extra kWh of energy. Energy costs can fluctuate on an hourly basis depending on the load level being served and the types of generating resources available in the market.

The Board will post on its website avoided cost data that distributors should use for undertaking benefit-cost analyses of CDM measures and programs.

While all CDM measures can provide demand savings, only those measures which reduce load during peak seasons should apply capacity savings for generation, transmission and distribution. Since the Ontario load profile is summer peaking, only those measures which reduce load during the summer shall apply the avoided cost of system capacity. However, since some distribution areas are winter peaking, measures which reduce winter load in those areas should include the value of avoided distribution capacity costs as one of the benefits.

3.2.2 Electrical Energy and Demand Savings

The benefits in the TRC test are driven by the annual energy (kWh/yr) and demand (kW) savings. Energy and demand savings are often calculated at the technology level and are commonly referred to as “prescriptive” savings estimates. For programs that rely on prescriptive savings estimates, savings are calculated by multiplying the per unit (i.e. single technology) savings with the number of units installed.

Savings and technology costs should be defined relative to a frame of reference or “base case”. To accurately specify the impacts of any given technology, the analyst must know what would have happened in the absence of the technology. The base case technology variable represents the piece of equipment or technology that is being replaced by a more efficient technology. The application of a base case technology can vary, for example, in the case of a CDM program consisting of a residential programmable thermostat; the base technology would be a manual thermostat. In the example of a program consisting of a high efficiency furnace, the base case equipment would be the homeowner’s current furnace. At a minimum, the base case technology must be equal to or more efficient than the technology benchmarks mandated in energy efficiency standards.

In practice, specifying savings relative to a frame of reference can be simply characterized by the three general decision types:

- new;
- replacement; or
- retrofit.

An example of how using a different base case can affect the energy savings estimates is provided in Appendix A.

In the TRC analysis, equipment life is used to determine the time period over which the net present value analysis is carried out. The equipment life variable represents the number of years that the more efficient equipment installed is assumed to produce energy savings. The benefits (i.e. energy and load savings) from an energy efficient piece of equipment are assumed to persist for the life of the equipment. Equipment life is estimated based on the nature of the equipment and an assumed usage pattern.

An important consideration when assessing equipment life is the potential difference between the energy efficient equipment and the “base case” equipment that is being replaced. A simplifying assumption in the case of replacement programs is that the energy efficient equipment lives are the same as in the base case. However, there are some technologies (such as lighting) where the energy efficient equipment may have a much longer life than the base case equipment. For example, a compact fluorescent bulb has an equipment life of up to 10,000 hours and would replace an incandescent bulb which has an equipment life of 1,000 hours. To accommodate this difference in the TRC analysis, the savings are assumed to persist for the entire 10,000 hours and the incremental cost should be adjusted to reflect the avoided purchase of 10 incandescent bulbs. This has the effect of enhancing the cost effectiveness of the compact fluorescent bulb measure.

The Board will post on its website TRC inputs and assumptions for a selection of measures, covering a range of typical CDM activities/technologies in residential, commercial and industrial applications. Distributors should use this data for undertaking benefit-cost analyses of CDM measures and programs.

Distributors may use other data, including free rider rates, where appropriate and justified. However, where a distributor uses other data, including other free rider rates, the distributor should provide as part of any filing for LRAM or SSM, detailed evidence to justify its use, including, at a minimum, a completed "Input Assumptions Template", attached as Appendix C.

3.3 TRC Costs

The TRC includes two types of CDM costs:

(1) equipment costs; and,
(2) program costs.

3.3.1 Equipment Costs

Typically in CDM programs, equipment costs are paid by the participant/customer. Customer equipment costs (sometimes termed "Participant costs") are the costs to purchase the more efficient equipment. They include both capital and operating and maintenance ("O&M") costs associated with the CDM program. It is important to note that the TRC test does not differentiate between who (distributor or customer) pays the cost of the equipment.

Customer costs can be incremental or full depending upon the nature of the energy efficiency investment decision. Incremental equipment costs are defined as the cost of the energy efficient technology above the base case technology. In the same way that the base case is important for specifying the savings, it is also important for specifying the cost of the energy efficient equipment. For example, in a replacement scenario, the cost of the energy efficient technology is typically incremental. In a retrofit or discretionary investment case, the cost of the energy efficient technology would be the full cost of the equipment.

Equipment costs, whether paid by the customer or the distributor, including purchase and installation, must always be defined relative to a base case. It is not enough to know the installed cost associated with the energy efficient equipment used in the program. To calculate the impact of the program, the cost of the equipment that would have been purchased in the absence of the program, the base case, must also be known. The appropriate specification of incremental cost for use in the TRC analysis is the difference between the base case and the energy efficient purchase.

An example of how costs will vary depending upon the base case assumption is provided in Appendix A.

As in the case of savings, there are typically three generic categories for specifying equipment costs, representing the type of investment decision:

- new;
- replacement; or,

- retrofit.

The information sources for equipment costs will vary. For residential equipment, retail store prices are appropriate sources of information for many technologies including lighting, appliances and “do-it-yourself” water heater or thermal envelope upgrades. It is common practice to specify an average price based on a sample of retail prices. For commercial and industrial equipment, cost data can be more complicated to acquire due to limited access and confidentiality concerns. For larger “custom” projects, invoices or purchase orders may be necessary to support the cost estimate.

Equipment that requires O&M expenditures is often not incremental (i.e., those costs would have been incurred in the base case anyway). However, if the energy efficient equipment requires significantly more maintenance than its less energy efficient counterpart, the incremental O&M costs need to be factored into the TRC analysis. There will be exceptions and a proper TRC analysis should incorporate these.

3.3.2 CDM Program Costs

From the perspective of the TRC test, CDM program costs are those incurred by the distributor. These costs include the marketing and support costs associated with delivering the CDM activity. Participant or customer incentive costs, which are considered transfers in the TRC test, are <u>not</u> included in the analysis.

Distributor costs typically cover a number of activities such as marketing and advertising, consulting, channel support, monitoring and evaluation. There are five major categories of distributor costs:

i. development and start-up;
ii. promotion;
iii. equipment and installation;
iv. monitoring and evaluation; and
v. administration.

In practice, all of these costs can be expected for programs that distributors in Ontario might be considering.   For an accurate TRC assessment, the distributor should ensure that all costs associated with designing, operating and tracking the programs, other than incentive costs, are accounted for in its TRC analysis.

i. Development and Start-up Costs

Development and start-up costs are different from on-going operating costs. For example, initial costs may be incurred to train distributor staff in the use of the equipment or techniques used in a program and usually occur at the early stages of the program’s life. Costs of developing CDM plans and procedures are also often concentrated in the early program years. In general, start-up costs are only a small component of the total costs in the life cycle of a CDM program.

ii. Promotion Costs

Promotion costs may be incurred to educate the customer about a CDM program and will vary by program type and level of promotional effort. The cost of promotion depends on the method employed, the market segment and the CDM measures promoted. Program promotion may also involve trade-offs between increases in promotion costs and expected increases in participation.

Examples of methods of promotion are provided in Appendix A.

The appropriate costs to be included in the TRC analysis are the equipment and program delivery costs. Incentive payments from the distributor to a customer for participation in a program are <u>not</u> a component of the TRC analysis, but still should be included in the distributor's program budget. The incentive merely represents a transfer payment between two parties involved in the program.

Appendix A contains further information on distributor costs for incentives, and on why the incentive amount is not included in the TRC analysis.

iii. Distributor Equipment and Installation Costs

Distributor equipment and installation costs include the costs of any distributor devices needed to operate the programs such as specialized software or tools, as well as any equipment directly installed by the distributor such as load control devices.

iv. Monitoring and Evaluation Costs

This section focuses on the cost to the distributor of monitoring and evaluating a CDM portfolio.

There are two broad categories of evaluation activity: impact evaluation and process evaluation. Impact evaluation focuses on the specific impacts of the program – for example, savings and costs. Process evaluation focuses on the effectiveness of the program design – for example, the delivery channel. The costs associated with each of these activities are program costs that need to be included in the TRC analysis. Some of these costs will be assigned directly to a specific program or programs, while a portion of the costs are more appropriately assigned across all programs (i.e., at the CDM portfolio level).

Monitoring and evaluation costs are incurred for systems, equipment and studies necessary to track measurable levels of program success (participants, load impacts and costs) as well as to evaluate the features driving program success or failure. It is important to develop the necessary tracking systems at the time of program design. At a minimum, the tracking system should collect information on the key components that drive the TRC test, including:

- number of participants/installations;
- energy and seasonal demand savings;
- cost of equipment; and
- distributor program costs.

To facilitate the evaluation of CDM programs and results, distributors should have clearly documented “paper trails”.

v. Administrative costs

Administrative costs are generally the costs of staff who work on CDM activities. These costs are often differentiated between support and operations staff. Support staff costs are considered fixed costs or “overhead” that occur regardless of the level of customer participation in the programs. Operations staff costs are variable, depending on the level of customer participation. Distributors should include all staff salaries that are attributable to CDM programs as part of the costs in the TRC analysis.

3.4 Adjustment Factors in the TRC Test

In performing a TRC analysis, several adjustments should be made to the benefits side of the equation. These adjustments include:

- free ridership of participants (section 3.4.1);
- attribution of the benefits (section 3.4.2);
- persistence of the measures (section 3.4.3); and
- distribution and transmission losses (section 3.4.4) **(New)**.

3.4.1 Free Riders

Free rider adjustments are one of the key components of the TRC test. The standard definition of a free rider is “a program participant who would have installed a measure on his or her own initiative even without the program”.[10] This participant simply uses the program to offset the cost of installing or undertaking the energy efficient initiative.

Costs and benefits associated with free ridership should be assessed as part of the TRC analysis. In determining overall savings, these participants are excluded from the benefits attributed to the program. The equipment costs associated with these participants is similarly excluded from cost side of the equation. [11] However, all program costs associated with free riders must be included in the analysis. Programs that have high free ridership are self-evident in the marketplace (i.e. they do not rely on

[10] Violette, Daniel M. (1995) *Evaluation, Verification, and Performance Measurement of Energy Efficiency Programs*. Report prepared for the International Energy Agency.
[11] Eto, J. (1998) *Guidelines for Assessing the Value and Cost-effectiveness of Regional Market Transformation Initiatives*. Northeast Energy Efficiency Partnership, Inc.

a distributor promotion) and are less cost effective since the program costs are included in the TRC calculation while the benefits are not.

3.4.2 Attribution

CDM activities are managed and/or delivered not only by electricity distributors, but also by others such as gas distributors, electricity retailers, gas marketers and the OPA.

A fundamental issue for the evaluation of CDM programs is whether the effects observed after the implementation of a distributor CDM activity can be attributed to that activity (otherwise known as causality) or result from the activities of others.

This section outlines the guidelines for attributing benefits between CDM measures delivered by distributors and those delivered by others.

While attribution is not a true adjustment to the TRC test, this issue is important for those distributors that plan on making an LRAM or SSM claim. Attribution of benefits between a distributor and a non-rate regulated third party was addressed in the Board's March 3, 2006 Decision in proceeding RP-2005-0020 / EB-2005-0523. In that Decision, the Board indicated that attribution will be determined on a case-by-case basis. In order for the distributor to claim 100% attribution of benefits, the distributor should demonstrate that its role was 'central' to the program.

The Board further stated that centrality is established by the distributor if its financial contribution is greater than 50% of program funding or, where the distributor's financial contribution is less than 50% of program funding, the distributor initiated the partnership, initiated the program or initiated the implementation of the program. Where the distributor's financial contribution is less than 50%, the Board expects that the distributor will provide supporting documentation outlining its role in the program.

By extension, should the distributors' role not meet the test of centrality, attribution should be determined between the parties and presented to the Board for approval at a time when it becomes relevant.

Appendix A provides further detail on how the attribution of benefits of a CDM program, and illustrates three cases where attribution may be an issue.

3.4.3 Persistence

Persistence is a measure of how long a CDM measure is kept in place by the customer. Persistence is important for all energy efficiency programs as a lack of persistence can have very significant effects on overall net program savings estimates. For example, if an energy efficient measure with a 15-year lifetime is removed after only two years, most of the savings expected to result from that installation will not materialize.

There is a compelling argument for accounting for persistence in the assessment of CDM cost effectiveness, especially for measures which are easily replaced such as compact fluorescent light bulbs. However, at this time, distributors should assume 100% persistence in assessing CDM cost effectiveness unless otherwise updated by the Board. While persistence is not likely 100%, for practicality, it is necessary to make some simplifying assumptions.

3.4.4 Distribution and Transmission Losses (New)

The Board previously examined the issue of distribution losses as part of the development of the 2006 Electricity Distribution Rate ("EDR") Handbook, and in particular, whether the cost of losses would continue to be a pass through cost to customers. In its Report of the Board on the 2006 EDR Handbook, issued May 11, 2005, the Board recognized that reducing line losses is an opportunity for conservation in Ontario. However, the Board concluded that distribution line loss variances would be difficult to isolate and quantify with precision, and that it would focus in 2006 on identifying those distributors with high average losses and require them to report on those losses and provide an action plan as to how they intend to reduce their respective levels of losses.

The Board examined the issue of losses again as part of the development of the TRC Guide. The Board concluded that while losses are a real part of the electrical distribution system, the variability and makeup of those losses created a significant challenge for the Board in calculating actual losses for each distributor. Further, excluding losses in the assessment of the cost effectiveness of CDM measures would create a level comparison of measures across the province.

It is clear that system losses are a reality for both distributors and the transmission grid. It is also intuitive that CDM initiatives that lower demand or energy use will also lower the system losses. By recognizing a program's potential to lower system losses, a program becomes more cost effective than it otherwise would have been, and therefore more worthwhile for a distributor to deliver the program. This is a positive outcome. As such, including losses in the calculation of the benefits of CDM is appropriate.

In addition to including system losses in the screening stage, when determining whether a program is cost effective, a consistent treatment suggests that losses should also be included in the calculation of SSM.

In Ontario, distribution infrastructure and load shapes vary significantly from distributor to distributor. This has a direct impact on distribution losses. Distributors with older systems could have higher losses than those with newer infrastructure. Distributors that have load shapes where there is a significant difference between the peak and the average load are also likely to have higher losses. System losses are significantly higher during peak demand periods because they vary by the square of the load.

Some distributors may be able to calculate their distribution losses with a fair degree of accuracy. Others may not, and in any event, the rate of losses will also vary from year to year as infrastructure is updated and load shapes vary. Given the variations, and the complexity of their sources, it is likely not appropriate to assign different loss values to different distributors (even if they are known). Rather, it is preferable to assign an average distribution loss "estimate" to distributors collectively.

In the past, Ontario Hydro included both transmission and distribution losses in the calculation of savings (and TRC benefits) resulting from CDM initiatives. An average loss of 4% for transmission and 4% for distribution was added to the savings calculations.

Based on the total volumes of electricity purchased and sold, as set out in the Board's 2005 Yearbook of Electricity Distributors and 2006 Yearbook of Electricity Distributors, the total loss factor in Ontario was 4.08% in 2005, and 4.20% in 2006. Data from the IESO shows that average transmission losses in Ontario are in the range of 2% to 3%. Therefore, an average loss of 4% for distribution remains appropriate for use in the current environment, but not for transmission. A loss value of 2.5% appears more appropriate for transmission losses, given the current range in Ontario.

Distributors should include distribution losses of 4% and transmission losses of 2.5% when undertaking a benefit-cost analysis of programs, and when calculating the SSM associated with a program. The result will be higher TRC benefits.

The losses should also be included in distributors' annual reports on their CDM activities. Finally, the use of the distribution and transmission losses in the TRC assessment should be done in a manner where both demand and energy are adjusted.

4.0 ACCOUNTING TREATMENT

4.1 Cost Allocation

As set out in the Framework Report, distributors are required to use a fully allocated costing methodology for all distributor-delivered CDM activities. Capitalized assets associated with CDM activities that are funded through rates will be included in rate base, and will be treated in the same manner as distribution assets. Assets purchased with funds from the OPA will not be eligible for inclusion in rate base, nor will any ongoing operating costs associated with the asset.

Where the funding is coming from the OPA, the separation in costs will appropriately establish distribution rates by eliminating any cross subsidization between OPA-funded CDM activities, and those activities funded through distribution rates. Where the funding would be from the distributor's rates, fully allocated costing will ensure that there is an appropriate basis to determine the cost effectiveness of CDM programs.

Attached as Appendix B to the draft Guidelines are guidelines to assist distributors with the implementation of fully allocated costing.

4.2 Revenue Allocation

As set out in the Framework Report, and consistent with the treatment of costs associated with OPA-funded CDM activities, revenues earned from OPA-funded CDM activities are to be kept separate from (i.e. not included in) the distributor's distribution revenue requirement.

Any net revenues generated by a shareholder incentive for distribution rate-funded CDM must also be separate from (i.e. not included in) the distributor's distribution revenue requirement.

4.3 Recording of CDM Spending

OPA-funded CDM programs are classified as non-distribution activities. Consequently, OPA-funded CDM revenues, expenses, assets or liabilities are not recognized for rate-setting purposes. The financial records associated with OPA-funded CDM should be separate from those associated with the distributor's distribution activities.

A distributor receiving OPA-funded CDM revenues and incurring related CDM expenses and/or capital expenditures should record these transactions in separate non-distribution accounts in the Uniform System of Accounts. For this purpose, account 4375, Revenues from Non-Utility Operations, should be used for revenues and account 4380, Expenses from Non-Utility Operations, should be used for expenses. Sub-accounts may be used as appropriate.

5.0 LOST REVENUE ADJUSTMENT MECHANISM (LRAM)

Unforecasted CDM results can have the effect of eroding distributor revenues due to lower than forecast throughput. Distributors recover fixed distribution costs through both a fixed and a variable rate, which is set based on a forecast of consumption, including natural changes in energy efficiency. If actual consumption is less than the forecasted amount used for rate-setting purposes, the distributor earns less revenue than it otherwise would have, all other things being equal. Since the intention and effect of CDM activities is to reduce capacity and energy use, it also has the effect of reducing throughput and associated distributor revenues, which can result in a disincentive for distributors to deliver CDM programs.

A mechanism to compensate for distributor-induced lost revenues is intended to remove the disincentive. LRAM is a retrospective adjustment, which is designed to recover revenues lost from distributor supported CDM activities in a prior year. It is designed to compensate a distributor only for unforecasted lost revenues associated with CDM activities undertaken by the distributor within its licensed service area.

In its December 10, 2004 decision in the proceeding on third tranche CDM activities (RP-2004-0203), the Board concluded that a lost revenue adjustment mechanism or LRAM was appropriate for electricity distributors, and that it should apply to CDM expenditures relating to the third instalment of distributors' MARR. The Board provided such a mechanism as part the 2006 EDR process. In the Framework Report, the Board confirmed the ongoing availability of LRAM.

5.1 Eligible programs

LRAM is available regardless of whether the programs are funded by the OPA or through distribution rates. The LRAM applies to programs implemented by the distributor, within its licensed service area, including programs delivered by the distributor itself and/or programs delivered for the distributor by a third party (under contract with the distributor, either in relation to rate-funded programs, or where the distributor has contracted with the OPA but has outsourced CDM program delivery to a third party).

Distributors may undertake some programs in partnership with other entities, such as natural gas utilities or community agencies. In assessing the distributor's involvement in program delivery, and the resulting potential impacts on revenue, distributors should be guided by section 3.4.2 of the draft Guidelines, regarding the attribution of benefits. Distributors may only recover LRAM for revenue losses that can be attributed to the distributor's involvement in the program.

5.2 Calculation of LRAM

The LRAM is determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class. The calculation does not include any Regulatory Asset Recovery rate riders, as these funds are subject to their own independent true-up process.

As confirmed by the Board's September 11, 2007 Decision and Order in proceeding EB-2007-0096,[12] the LRAM amount to be recovered in rates should be adjusted for free riders. As noted above, free riders are those customers who would have adopted or installed an energy efficiency measures regardless of the involvement of the distributor. This is often called natural conservation. Given that the LRAM is intended to compensate distributors for revenue losses resulting from the distributor having implemented a CDM program, the LRAM should be adjusted to remove the free riders.

As indicated by the filing guidelines set out in section 9.2, distributors should include in the application for recovery of LRAM the kW or kWh impacts of each program and for each class both gross and net of free riders. The amount to be recovered through rates will be determined as net of free riders.

[12] An application by Toronto Hydro-Electric System Ltd. for recovery of LRAM and SSM (EB-2007-0096).

6.0 SHARED SAVINGS MECHANISM (SSM)

LRAMs remove a disincentive for distributors to implement CDM, but do not provide an incentive for distributors to aggressively implement CDM programs. Given a certain level of resources, the distributor must make a trade-off between pursuing a CDM activity versus other activities.

In its December 10, 2004 decision in the proceeding on third tranche CDM activities (RP-2003-0203), the Board found that a shareholder incentive was an appropriate way to encourage distributors to pursue CDM programs. The Board confirmed this view in the Framework Report.

6.1 Eligible programs

The SSM is available for customer-side programs that are funded through distribution rates, such as efficiency improvements in the use of electricity. The SSM is not available for utility-side expenditures such as distribution system improvement projects, or programs that are not funded through distribution rates, such as those funded by the OPA.

Distributors may undertake some programs in partnership with other entities, such as natural gas utilities or community agencies. In assessing the distributor's involvement in program delivery, distributors should be guided by the guidelines set out in section 3.4.2 of the draft Guidelines, regarding the attribution of benefits. Distributors may only claim a shareholder incentive in relation to its contribution to the program, as determined by the attribution guidelines.

6.2 Calculation of SSM

The distributor should calculate the net benefits of a program using the TRC test, and adjusting for free riders. Under the SSM regime, a distributor may recover 5% of the net benefits created by the approved CDM portfolio. As confirmed by the Board in its September 11, 2007 Decision and Order in proceeding EB-2007-0096, the SSM is a pre-tax amount. In addition, the SSM should be calculated across the entire portfolio of CDM programs, including any programs with negative benefits.

7.0 PROGRAM EVALUATION

Effective monitoring, evaluation, verification and reporting of CDM program outcomes is a critical part of ensuring that programs are cost effective, generating the desired outcomes, and providing real savings to consumers. Evaluation also provides distributors with the opportunity to identify ways in which a program can be changed or refined for greater efficiency in delivery and cost effectiveness.

Distributors are required to undertake evaluations of programs funded through distribution rates. The evaluation of CDM activities is important to support the Board's review and approval of LRAM and SSM claims made by distributors. Evaluation of the energy savings of a program is needed to determine the impact on a distributor's revenues as a result of reduced throughput.

The California Evaluation Framework identifies two key functions of evaluation:

1. To document and measure the effects of a program – "Summative Evaluations".
2. To help understand why those effects occurred and identify ways to improve the program – "Formative Evaluations".

The first function represents a threshold for assuring accountability for the expenditure of resources on that program. Evaluation activities are done after the program has been operating and focus on documenting impacts with a view to informing decisions regarding continuation, expansion or cancellation of the program. Formative evaluations (often referred to as process evaluations) may be done earlier in a program's continuum and focus on providing feedback regarding the operational effectiveness of a program. The results of the evaluation serve to inform decisions regarding mechanisms to improve the program.

For distributors in Ontario, much of the focus to date has been on the design and delivery of the programs. With the exception of the annual CDM reporting as directed by the Board, most distributors have not undertaken rigourous verification or evaluation activities in support of their programs. As distributors continue to offer CDM programs that are funded through distribution rates, many with associated shared savings incentive and lost revenue adjustment calculations and applications, it is incumbent on the Board to ensure that the various programs are actually achieving what is claimed. Further, it is also important to ensure that CDM investments are garnering results in the most effective manner. As such, a more rigourous evaluation framework should be considered.

Distributors in Ontario that offer distribution rate funded CDM programs are required to provide an annual report to the Board which provides details on the programming results, including savings, costs and TRC results. While these represent a good reporting foundation, they cannot be considered evaluations. Undertaking rigourous evaluation requires specialized skills and competencies that may encompass market research, billing analysis, econometric techniques, survey research, metering, cost effectiveness analysis and related assessments. The exact requirements will vary depending on the program and the nature of the evaluation will be dictated both by the parameters of the program and the budget allocated for evaluation activities.

A key tenet of good program evaluation practices is the identification of the evaluation requirements as part of the initial program design. This ensures that the operational characteristics of the program generate the data and information that can assist in the program evaluation. This can be as simple as collecting relevant contact information as part of the operation of the program which will be used in follow-up activities, or more complicated activities such as pre and post implementation metering of equipment. In both cases, the evaluation techniques and parameters are integrated with the design and operation of the program.

To date, the only related direction from the Board has focused on annual reporting. For most distributors, preparation of annual reports to the Board on CDM activities generally relies on monthly tracking of program participation, use of the Board Assumptions and Measures List for savings, costs and free rider estimates and engineering reports for custom project results. Participation rates are typically determined as part of the delivery of the program (for example, redeemed coupons, retailer sales data, customer sign-ups etc.).

Finally, it is incumbent on distributors to attempt to improve their programming capabilities over time. This requires re-visiting the programs from time to time through the use of process evaluations that examine the effectiveness of the delivery. All programs should consider a certain level of process evaluation effort at some point. Typically, process evaluations occur earlier in a program's life rather than later – i.e. early enough to revise the program as a result of the evaluation. This will vary based upon the size and nature of the programs, where they are in their life, and the similarity (or lack of similarity) to other distributor programs. For small programs, the evaluation effort could focus on secondary research augmented by interviews with key personnel involved in the program. Larger programs might require greater depth of evaluation including market research, surveys with participants and non-participants and related primary research activities. In the end, the intent is to ensure that programs operate at the highest level of effectiveness and that the process evaluation results are made available to other distributors to assist them in their delivery.

7.1 Evaluation Plan (New)

An overarching requirement for effective evaluation is the need to identify, at the outset, how each program will be evaluated. This establishes both the individual metrics that will be measured/tracked and evaluated and the mechanisms that will be used. It further ensures that the evaluation effort is adequately contemplated and resourced.

Distributors should file an Evaluation Plan along with the application for funding for any program(s). Approval of the distributor's CDM plan will be conditional upon approval of an acceptable Evaluation Plan for the program(s) contained in the CDM plan.

The purpose of the Evaluation Plan will be to identify the key evaluation metrics, activities and outcomes associated with each of the distributor's CDM programs.

It is recognized that not all programs will require an evaluation effort in each year. However, at a minimum the distributor should anticipate and plan for a certain level of evaluation activities over the continuum of a program's life.

In addition to meeting the evaluation objectives listed below, any Evaluation Plan should include the distributor's proposed methodology for:

- Measuring program effects (summative evaluation); and,
- Assessing why effects occurred, and how the program can be improved (formative or process evaluation)

The Evaluation Plan(s) should outline how the distributor will accomplish the following evaluation objectives:

- Measuring the level of energy and peak demand savings achieved;
- Measuring cost-effectiveness;
- Informing decisions regarding LRAM and SSM amounts;
- Providing ongoing feedback, and corrective and constructive guidance regarding the implementation of programs; and,
- Helping to assess whether there is a continuing need for the program.

7.2 Program Type Specific Guidelines

This section focuses on the guidelines, in addition to those set out above, for tracking and measuring the effects of the following four types of CDM programs:

1. **Direct acquisition** programs are programs that have clear causality between distributor activity and energy savings.
2. **Market support/outreach** programs are programs in which the distributor supports outreach or educational efforts which generally promote the energy efficiency message, but where savings are indirect and it is difficult to see a clear cause and effect relationship.
3. **Custom projects** are those projects that involve customized design and engineering, and where a distributor facilitates the implementation of specialized equipment and technology that is not identified in the list of TRC inputs and assumptions posted on the Board's website.

7.2.1 Direct Acquisition Programs

Direct acquisition programs are relatively straightforward to track and measure. Tracking represents one of the administrative functions of program delivery. While the specifics will vary for each type of program, there is a need to show clear cause and effect between the distributor's activities and the customer's load reduction. In direct acquisition programs, this is often precipitated by the processing of a participant incentive. Distributors will need to have systems for collecting relevant information for each program, including:

- technology type;
- number of installations;
- savings estimates;
- equipment cost estimates;
- customer address or location;
- delivery channel; and,
- incentive amount.

It may not be feasible to collect all information for all programs. For example, a program delivered by a retailer that relies on in-store coupons will likely not have the means to track who actually used the coupons and received the product(s). However, the retailer can be expected to track information about the number of coupons turned in, and the distributor's tracking system could then calculate the resulting cost to the distributor. With this information, the distributor can then calculate the savings and equipment cost and combine the information with equipment life, free rider estimates and program costs - resulting in both a tracking report and the requirements for the TRC analysis.

In the case of a program delivered by a third party, tracking will include reports that the delivery partner provides to the distributor. These reports should provide details on the customer visits, including address and equipment installed.

7.2.2 Market Support Programs

Load reductions from CDM activities related to training, public outreach and the general provision of information on efficient energy use are difficult to track, measure and establish clear causality. Since market support programs typically do not result in direct demand or energy savings, other assessment criteria should be used to assess their benefits. Each market support activity should attempt to have at least one metric.

Below is a sample of potential tracking activities that might accompany the delivery of market support programs. Each market support activity should attempt to have at least one metric.

Support	Metric	Additional Information
Web-site calculator	Number of hits	Survey re: usefulness of website
Training sessions for contractors	Number of sessions Number of attendees	Survey re: specific activities undertaken by attendees
Home shows	Number of giveaways	Survey re: energy efficient appliances

Design workshops	Number of professional attendees	Surveys re: design activities

7.2.3 Custom Projects

Custom projects are those projects that involve customized design and engineering, and where a distributor facilitates the implementation of specialized equipment and technology not identified in the list of TRC inputs and assumptions posted on the Board's website. Projects that involve a combination of several measures provided in the list of TRC inputs and assumptions posted on the Board's website are not considered to be custom projects.

For a custom project, distributors will need to track:

- the type of equipment that was installed;
- the related savings and equipment cost; and,
- distributor support costs.

Since custom projects usually involve specialized equipment, savings estimates should be assessed accordingly. It is expected that each custom project will incorporate a professional engineering assessment of the savings. This assessment would serve as the primary documentation for a claim that savings exist.

A special assessment program should be implemented for custom projects. The assessment should be conducted on a random sample consisting of 10% of the large custom projects; and the projects should represent at least 10% of the total volume savings of all custom projects. The minimum number of projects to assess would be 5. Where less than 5 custom projects have been undertaken, all projects should be assessed. The assessment will focus on verifying the equipment installation and estimates of savings and equipment cost.

7.3 Implementation of Updated Input Assumptions (New)

The input assumptions used to screen CDM technologies and programs may change over time due to more accurate and up-to-date information. This can impose a risk on distributors that the actual program impacts, LRAM or SSM are not those expected based on a given set of assumptions. The timing at which changes in assumptions become effective will differ depending the use of the assumption, as follows:

Program Design and Implementation
Programs should be designed, screened and evaluated using the best available information. Therefore, it is expected that distributors incorporate new information into program design and implementation as soon as feasible.

LRAM
The input assumptions used for the calculation of LRAM shall be the best available at the time of the application to the Board. For example, if any input

assumptions change in 2007, those changes shall apply for LRAM purposes from the beginning of 2007 onwards until changed again.

SSM
Assumptions used from the beginning of any year will be those assumptions in existence in the immediately prior year. For example, if any input assumptions change in 2007, those changes shall apply for SSM purposes from the beginning of 2008 onwards until changed again.

7.4 Evaluation Report (New)

A distributor that makes an LRAM or SSM claim, whether in relation to programs funded by the OPA or through distribution rates, will need to file a more detailed Evaluation Report at the time of making that claim. The Evaluation Report should consist of the following sections:

(1) Introduction
In the "Introduction" section of the Evaluation Report, distributors should provide a general overview of their CDM initiatives including any relevant local context.

(2) Evaluation of the CDM Plan
This section will provide an overview of the effectiveness of a distributor's CDM Plan. Distributors should report on all initiatives worked on and detail the process and impact analysis of the individual programs.

Note:
Stand alone education or marketing programs that do not have quantifiable benefits should report all relevant information (some relevant assessment criteria are identified in section 7.2.2 of the draft Guidelines). Marketing or support programs (i.e., programs designed to enhance market acceptance of other programs) should not be reported individually as they are components of other programs. Similarly, the costs of marketing or support programs should be allocated to the programs they support.

Distributors who have pilot programs, as defined in section 2.1.2 of the draft Guidelines, or other programs for which cost effectiveness data was not provided by the Board (on the Board's website) should provide their own values, if available, and report all relevant information (attach a separate table if required).

If the TRC test inputs used by the distributor vary from those posted on the Board's website, the variation(s) should be identified, and additional information supporting the variation(s) should be filed. If the specific technology promoted by a distributor was not included by the Board (on the Board's website), the distributor may select a similar technology as a proxy for annual reporting purposes. A distributor that selects a proxy technology for reporting should identify the actual technology in its Evaluation Report and the similarities between the proxy technology and the actual technology. However, for the purposes of a claim for recovery of LRAM or SSM, where a distributor uses a proxy technology, the distributor should provide detailed evidence justifying the appropriateness of using the proxy technology, and detail the steps the distributor has taken, or will take, to determine the actual data for the technology used in the CDM program.

(3) Lessons Learned
In the "Lessons Learned" section the distributor will indicate what has been learned over the course of the program. The goal of this section is to evaluate and benchmark programs for greater efficiency in delivery and cost effectiveness, and to provide information to other distributors with respect to CDM programs. Distributors should indicate if a program is considered a success or not and whether the distributor should continue its delivery.

(4) Conclusion
The "Conclusion" section will consist of the distributor's summary of its performance relative to the CDM Plan approved by the Board.

7.5 Requirement for An Independent Third Party

Given the ratemaking implications of program evaluations, intervenors, ratepayers and the Board need to be confident that evaluations are an accurate reflection of actual program results. Where a distributor is making a claim for LRAM in relation to programs funded by the OPA, or where the distributor is making a claim for LRAM and/or SSM in relation to programs funded through distribution rates in 2007 and beyond, there is a requirement for the involvement of an independent third party.

<u>OPA Funded CDM Programs</u>

As part of a claim for LRAM in relation to programs funded by the OPA, the Framework Report sets out the requirement for distributors to submit to the Board an independent third party evaluation of program results.

For programs funded by the OPA, it will be the role of the third party to:

- Verify the participation levels; and,
- Confirm that input assumptions are those used by the OPA.

<u>CDM Programs Funded Through Distribution Rates</u>

In relation to programs funded through distribution rates, the Framework Report sets out the requirement for distributors to undertake program evaluations, and to have the evaluations reviewed by an independent third party for the purposes of LRAM and SSM claims filed with the Board.

The third party, although hired by the distributor, should be independent and must ultimately serve to protect the interests of ratepayers. In addition, distributors should ensure that CDM budgets and spending include adequate funding to procure the required third party review.

For programs funded through distribution rates, it will be the role of the third party to:

- Provide an opinion on the cost effectiveness results that are material to the LRAM and SSM amounts proposed;
- Verify the participation levels;
- Confirm that the input assumptions are those posted on the Board's website;
- Where the distributor has used input assumptions other than those posted on the Board's website, review the reasonableness of the input assumptions used;
- Recommend any forward looking evaluation work to be considered; and,
- Recommend any improvements to the program to enhance program design, performance, and uptake by customers.

8.0 ANNUAL REPORTING GUIDELINES

The guidelines set out in this section relate only to CDM programs funded through distribution rates.

Reporting on the progress and success of CDM programs is critical to maintaining accountability and transparency. For programs funded through distribution rates, distributors should file annual reports, by April 30 of each year. Where distributors have approved funding for more than one year, a report should be filed annually summarizing the results of the previous year, and at the end of the plan term, addressing results for the entire plan term.

Given that distributors may have approved CDM plans that span more than one year, annual reporting will be an important tool to allow the Board and stakeholders to monitor distributors' year-over-year progress in the implementation of their CDM plans. The annual report should provide the Board and stakeholders with information on what CDM activities the distributor is undertaking, how it is performing, what it is costing, and the distributors' planned future activities.

Where distributors have separate streams of funding, for example, third tranche and 2007 funding, differentiating these results is a requirement in the Annual Report.

The Annual Report should consist of the following sections:

1. **Introduction**
   In the "Introduction" section of the annual report, distributors should provide a general overview of their CDM initiatives including any relevant local context.

2. **Description of the program**
   In this section, the distributor should provide an overview of the program, including the targeted customer class or group, the objectives of the program, and any activities associated with the program.

3. **Participation levels**
   In this section, distributors should detail the number of participants for each program.

4. **Energy savings in kW and kWh**
   In this section, distributors should provide the annual and cumulative energy savings attributable to each program, presented as both net and gross of free riders.

5. **Comments**
   In this section, distributors should provide any additional information as appropriate. This may include the distributor's assessment of the success of

the programs to date, what activities are planned for the subsequent year(s) and any planned modifications to program design or delivery.

ADMINISTRATION

9.0 FILING GUIDELINES

This section contains the Board's filing guidelines for the following types of applications:

9.1 Program funding through distribution rates
9.2 Lost Revenue Adjustment Mechanism
9.3 Shared Savings Mechanism
9.4 Adjustments to an approved CDM plan

The Board expects that distributors will comply with these filing guidelines as a minimum. Distributors are reminded that they should in all cases demonstrate to the satisfaction of the Board that any given application should be approved, and are responsible for ensuring to that end that all relevant information is before the Board (including evidence that may have been filed in an earlier proceeding). In addition, the Board may make any order or given any direction as the Board determines necessary concerning any matter raised in relation to any of the above applications, including in relation to the production of additional information which the Board on its own motion or at the request of a party considers appropriate.

9.1 Program Funding through Distribution Rates

Information required when filing an application for new funding through distribution rates includes:

1. **Characteristics of the applicant's distribution system, including:**
   - Peak system load by season;
   - Average seasonal daily and weekly system load shapes;
   - Total energy purchases;
   - Sales by rate class; and
   - Number of customers by rate class.

2. **For each initiative, the following information should be provided:**
   - Detailed description of the programs;
   - Customer class(es) targeted;
   - Projected incremental demand (kW) or energy (kWh) savings per year;
   - Projected budget, listing:
     - capital expenditures per year, for each year of the plan;
     - operating expenditures per year, for each year of the plan, separated into direct and indirect expenditures;
     - for each direct operating expenditure, an allocation of the expenditure by targeted customer classes; and
     - expenditures required for evaluation of the program(s).
   - Measure, programs and portfolio cost effectiveness results;

- The input assumptions underlying the forecasted savings and costs including a detailed presentation of the calculations;
- Where savings information is not provided in the list of TRC inputs and assumptions posted on the Board's website, the distributor should comply with the guidelines set out in section 7.2.3 respecting custom projects;
- A statement as to whether the distributor has deviated from the list of TRC inputs and assumptions posted on the Board's website. Where the distributor has deviated from the list of TRC inputs and assumptions posted on the Board's website, the distributor should provide, in accordance with section 3.2.2 of the draft Guidelines, detailed evidence to support the alternative data, including, at a minimum, a completed "Input Assumptions Template", attached as Appendix C to the draft Guidelines;
- The benefit-cost analysis, calculating the net present value of the initiative using the TRC test. For the purpose of calculating the net present value, a distributor should use a discount rate equal to the incremental after-tax cost of capital, based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity;
- For any pilot programs, as defined in section 2.1.2 of the draft Guidelines, a certification that, to the distributor's knowledge, the technology is not being used or tested by any other distributors, or is being used or tested only in a limited capacity; and,
- A discussion of whether the proposed initiative is similar to any currently offered by the OPA.

3. **The distributor should also provide the following, set out on a per year basis, for each year of the plan:**
   - The total amount of CDM spending to be recovered in rates and the allocation of those costs to the customer class(es) that will benefit from the conservation program applied for;
   - A forecast of the number of customers in each class and a forecast of kWs or kWhs to be used as a charge determinant to determine the rate rider for each class to benefit from the CDM program; and
   - A comparison of the proposed rates with and without the CDM rider for the rate year in question.

4. **An Evaluation Plan, in accordance with section 7.1.**

9.2 Lost Revenue Adjustment Mechanism (LRAM)

When applying for LRAM, a distributor should ensure that sufficient time has passed to ensure that the actual information needed to support the application is available.

Distributors will be expected to calculate the energy savings by customer class and to value those energy savings using the Board-approved variable distribution charge appropriate to the class. Lost revenue will be calculated using the variable distribution rate (kW or kWh) for each affected class and would not include any Regulatory Asset Recovery rate riders, as these funds have their own independent true-up process in place. In addition, lost revenues are only accruable until new rates (new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time.

Information required when filing an application for LRAM includes:

OPA Funded Programs

- kW or kWh impacts (both gross and net of free riders) of *each program* and for each class;
- The free rider rate applied to each program;
- A calculation of the impact of the CDM program on distribution revenues in each class;
- Verification of the participation levels;
- Duration of the program in years or months;
- An Evaluation Report, in accordance with the guidelines set out in section 7.4; and,
- Any reports completed by an independent third party, in accordance with the guidelines set out in section 7.5

Programs Funded through Distribution Rates

For programs funded through third tranche, and 2006 incremental funding:

- kW or kWh impacts (both gross and net of free riders) of *each program* and for each class;
- The free rider rate applied to each program;
- A calculation of the impact of the CDM program on distribution revenues in each class;
- Verification of the participation levels;
- Where savings information is not provided in the list of TRC inputs and assumptions posted on the Board's website, the distributor should comply with the guidelines set out in section 7.2.3 respecting custom projects;
- A statement as to whether the distributor has deviated from the list of TRC inputs and assumptions posted on the Board's website. Where the distributor has deviated from the list of TRC inputs and assumptions posted on the Board's website, the distributor should provide, in accordance with section 3.2.2, detailed evidence to support the alternative data, including, at a minimum, a completed "Input Assumptions Template", attached as Appendix C to the draft Guidelines; and,
- Duration of the program in years or months;

For programs funded in 2007 and beyond, the following information is required, in addition to the guidelines set out above:

- An Evaluation Report, in accordance with the guidelines set out in section 7.4; and,
- All reports completed by an independent third party, in accordance with the guidelines set out in section 7.5.

All information filed for the LRAM proposal should correspond to program information used in the calculation of the benefit-cost analysis.

9.3 Shared Savings Mechanism (SSM)

When applying for SSM, a distributor should ensure that sufficient time has passed to ensure that the actual information needed to support the application is available.

The distributor should calculate the net benefits of a program using the TRC test. Under the SSM regime, a distributor may recover 5% of the net benefits created by the approved CDM portfolio, through a rate rider. SSM applies only to customer focused initiatives that reduce the demand for electricity and/or reduce the amount of energy used and only where the costs of the initiatives are expensed.

Information required when filing an application for SSM includes:

For programs funded through third tranche, and 2006 incremental funding:

- kW or kWh impacts (both gross and net of free riders) of each program and for each class;
- A calculation of the impact of the CDM program on distribution revenues in each class;
- Verification of the participation levels;
- Where savings information is not provided in the list of TRC inputs and assumptions posted on the Board's website, the distributor should comply with the guidelines set out in section 7.2.3 respecting custom projects;
- A statement as to whether the distributor has deviated from the list of TRC inputs and assumptions posted on the Board's website. Where the distributor has deviated from the list of TRC inputs and assumptions posted on the Board's website, the distributor should provide, in accordance with section 3.2.2, detailed evidence to support the alternative data, including, at a minimum, a completed "Input Assumptions Template", attached as Appendix C to the draft Guidelines; and,
- Duration of the program in years or months;

For programs funded in 2007 and beyond, the following information should be provided in addition to the information set out above:

- An Evaluation Report, in accordance with the guidelines set out in section 7.4; and,
- All reports completed by an independent third party, in accordance with the guidelines set out in section 7.5.

9.4 Adjustments to an Approved Plan

The Board encourages distributors to evaluate the effectiveness of programs on an ongoing basis, and to make adjustments as necessary to improve program design, performance, and uptake by customers. Where cumulative fund transfers among programs are less than 20% of the approved annual budget, no Board approval is required.

Board approval is required for cumulative fund transfers among programs that exceed 20% of the approved annual budget.

An application for adjustments to an approved plan should include:

- Current and proposed budgets for programs affected by the re-allocation;
- A description of the programs from which, and to which, funds are being re-allocated;
- Whether the distributor is requesting that the Board to proceed in accordance with section 21(4)(b) of the *Ontario Energy Board Act, 1998*, under which the Board can dispose of the proceeding without a hearing;
- Where funding is being allocated to a program or programs that are not part of the distributor's approved CDM plan, the distributor should also follow the guidelines set out in section 9.1 in relation to the new program(s). That is, in addition to applying for approval for the proposed budget re-allocation, the distributor should also apply for approval of the proposed new program(s).

APPENDIX A:

Total Resource Cost Guide

Appendix A - Total Resource Cost Guide

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Overview

The *Total Resource Cost Guide* (the "TRC Guide") is a companion document to the Board's draft Guidelines for Electricity Distributor Conservation and Demand Management (the "Guidelines") and provides additional information to assist electricity distributors in preparing benefit-cost analyses of CDM programs. It is an explanatory document for undertaking TRC cost effectiveness analysis, and includes the mathematical formulae and sample TRC calculations.

The examples set out in this document are for illustrative purposes only, and do not necessarily represent actual costs, energy consumption or energy savings.

1.0 The Total Resource Cost Model

As set out in the draft Guidelines, CDM initiatives should be evaluated on the basis of a cost effectiveness test known as the Total Resource Cost (TRC) test**.** The TRC test is defined as a test that *"measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participant's and the [distributor's] costs".*[1]

1.1 Formula for Performing TRC Test

The TRC test examines streams of benefits and costs and uses discounting principles to express these future values as a single number. The benefits stem from the avoided resource costs, typically electricity. The costs are the cost of the equipment and the distributor program costs. Subtracting the costs from the benefits provides the net benefits. For a program to be considered cost effective, the net benefits must be greater than zero.

The NPV_{TRC} formula is as follows:

Figure 1.1: Net Present Value$_{TRC}$ Formula

$$NPV_{TRC} = B_{TRC} - C_{TRC}$$

where;

$$B_{TRC} = \sum_{t=1}^{N} \frac{AC_t}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{UC_t + PC_t}{(1+d)^{t-1}}$$

and,

B_{trc}	=	the benefits of the program
C_{trc}	=	the costs of the program. Where a measure includes fuel switching for a given end use, the cost of the other fuel must be included in the cost component of the TRC formula.
AC_t	=	avoided costs in year t
UC_t	=	distributor program costs in year t
PC_t	=	Participant cost in year t
N	=	Number of years for the analysis (i.e. the equipment life of the CDM technology)
d	=	discount rate. For the purposes of calculating the net present value,

[1]California Public Utilities Commission. (2001) Standard Practice Manual: Economic Analysis of Demand-Side Management Programs and Projects.

distributors must use a discount rate equal to the incremental after-tax cost of capital, based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity. This is consistent with the manner in which net present value calculations are done for purposes of the Distribution System Code.

1.2 Electrical Energy and Demand Savings

Section 3.2.2 of the draft Guidelines discusses the role of energy and demand savings in the TRC test. The frame of reference assumed can dramatically alter the energy savings estimates. The example set out below assumes that a distributor may wish to offer a program targeting *replacement* of old primary refrigerators with Energy Star™ refrigerators, or may offer a program that targets the complete *removal* of old secondary refrigerators.

Example of Replacement and Removal Programs

	Decision / Program	Existing Equipment	Base Case	Equipment	Savings	Measure Lives
A	Replace old primary refrigerator with a new one	1960's vintage refrigerator using 1,500 kWh/yr	Standard refrigerator using 514 kWh/year	New Energy Star refrigerator using 440 kWh/yr	Base Case – Energy Star 514 – 440 = 74 kWh/yr	19 years
B	Retire and remove old secondary refrigerator	1960's vintage refrigerator using 1200 kWh/yr	Keep using existing refrigerator		1200 kWh/yr	6 years

In this example, depending if the old refrigerator is the primary or secondary refrigerator in the home, and whether it is replaced or completely removed (i.e. different base cases), there is a significant difference in the savings estimates.

A) Replace old primary refrigerator with a new one:
In the case of the replacement, the distributor must estimate the energy use for both the "base case" equipment (i.e. the standard refrigerator) and the Energy Star™ higher efficiency refrigerator. In this case, the base case refrigerator uses 514 kWh/yr while the energy efficient refrigerator uses 440 kWh/yr. Since the program targets the installation of an Energy Star™ refrigerator over the base case option, the difference of 74 kWh/yr is the appropriate savings estimate for the program.

B) Retire and remove old secondary refrigerator:
For the removal program there is no replacement with either a base case or energy efficient model. Since the program encourages the removal of the old refrigerator, the appropriate savings estimate is 1200 kWh/year.

Load impacts must be defined in a manner consistent with other assumptions in the CDM program assessments. Impacts must be calculated over the same time horizon used in the program design and for the same costing periods used in defining the marginal costs. Impacts must also be consistent with the base case option used to measure incremental costs (see 1.3.1 - Equipment Costs).

1.3 Equipment Costs

Section 3.3.1 of the draft Guidelines discusses equipment costs, and how these are used in a TRC analysis. The example below uses the same refrigerator example as above to show how the costs will vary depending upon the base case assumption.

Understanding Incremental Costs for TRC Analysis

	Decision / Program	Baseline Equipment	Equipment Cost	Cost
A	Replace old primary refrigerator	1960's vintage refrigerator using 1200 kWh/yr	Base Case refrigerator: $1,000 Energy Star refrigerator: $1,070	"Energy Star" + Removal Fee – Base Case fridge $1,070 + 100 – $1,000 = $170
B	Retire and remove old secondary refrigerator	1960's vintage refrigerator using 1200 kWh/yr	$0	Removal fee estimated to be $100

A) Replace old primary refrigerator
The replacement scenario requires knowledge about both the cost of the base case equipment, the energy efficient equipment and the cost of removal and disposal. The cost to be used in the TRC analysis is the difference between these.

B) Retire and remove old secondary refrigerator
For the refrigerator removal scenario the only costs of the program are those for removal and disposal.

1.4 CDM Program Costs

Section 3.3.2 of the draft Guidelines discusses how promotion costs are used in a TRC analysis. Below are some sample methods of promotion.

Methods of Promotion

Type of Contact	Tactics
Personal contact with distributor representative	Telemarketing Customer service campaign Door-to-door campaign
Other direct distributor contact	Bill stuffers Direct Mail
Mass media	Print/flyers Television/Radio
Trade allies	Equipment vendors Equipment installers

Note on Distributor Costs for Incentives

While incentives primarily serve to improve the economic attractiveness of CDM investments for the customer, they also serve to increase customer awareness of the programs. As well, an incentive creates a specific paper trail that distributors can use as part of their tracking and evaluation activities.

Distributors may design incentive schemes specific to their customers. Often, payback criteria or rebates are used in incentive design. This approach is often more important to commercial and industrial customers. For these customers, many distributors favour an approach that lowers the payback to a specific threshold, or ensures that incentives are only applied to projects with paybacks above a certain threshold.

An alternative approach is to gauge rebate levels relative to the incremental capital cost of the CDM technology compared to a standard technology that would have been installed in the absence of the program. Rebates are often set at some percentage of incremental cost. In practice, those percentages vary from a fraction of the incremental cost to completely off-setting the incremental costs.

As discussed in section 3.3.2 of the draft Guidelines incentive payments from the distributor to a customer for participation in a program are not a component of the TRC analysis, but still should be included in the distributor's program budget. The following formula illustrates why the incentive amount is not included in the TRC analysis:

The costs of a program are distributor program costs (UC_t) plus participant cost (PC_t), while the benefits are the avoided costs (AC_t.). If the formula were to include the incentive amounts (INC_t), it could be re-written as:

Costs = $UC_t + PC_t + INC_t$
Benefits = $AC_t + INC_t$

Since the INC_t term is the amount paid by the distributor for the benefit of some third party, it is both a cost and a benefit in the equation. Therefore, for simplicity it can be eliminated from the analysis.

The exclusion of incentives is only for the purposes of calculating the TRC value of a program and they are not excluded in developing the distributors CDM budget. It is important to recognize that the only difference between the utility costs that get recorded in a distributor's TRC analysis and its complete CDM budget is the amount of incentives.

Many CDM programs involve some form of transfer payment (i.e. incentive) between distributors and participants. They are generally characterized as follows:

- rebates;
- loans and leases;
- shared savings arrangements; or,

- participation fees.

1.5 Categorizing Costs

As a matter of practice and for ease of performing cost effectiveness testing, many distributors categorize costs as either direct or indirect.

Direct costs are those that can be clearly allocated to a particular program and may include marketing, consulting and field staff costs among others. Direct costs factor into the program level cost effectiveness analysis. Indirect costs are those costs that can not easily be allocated to any particular program. These costs include overhead, administration and monitoring and evaluation. Indirect costs are typically incurred at the portfolio level and included in the portfolio cost effectiveness analysis.

2.0 Adjustment Factors in the TRC Test

As discussed in section 3.4 of the draft Guidelines, in performing a TRC analysis, several adjustments must be made to the benefits side of the equation, including:

- free ridership of participants;
- attribution of the benefits;
- persistence of the measures; and,
- distribution and transmission losses.

This section provides additional information on attribution.

2.1 Attribution

Section 3.4.2 of the draft Guidelines discusses the attribution of benefits between CDM activities funded through distribution rates and activities undertaken by other delivery agents and for savings associated with other resources.

The following discussion addresses the issue of attribution of benefits of a CDM program with respect to the potential claim for a Shared Savings Mechanism ("SSM"). In the case that an SSM is recovered, it must be paid by those ratepayers who are receiving the benefits of the program, therefore, guidelines have been established to attribute the benefits of a program along geographic and industry boundaries.

2.1.1 Attribution Guidelines for CDM Programs

The formula for determining savings associated with a CDM program is:

Savings = (UATES) x (NUD) x (1-FRR)

where;

Savings – kWh/yr and/or other resource measure;

UATES – Unit Annual Total Energy Savings

NUD – Number of Units Delivered

FRR – Free Ridership Rate

In order to estimate the savings attributable to the distributor program an attribution rate is added to the previous formula to get:

Attributable Savings = (UATES) x (NUD) x (1-FRR) x (AR)

where;

AR – Attribution Rate

In most cases, the attribution rate will be 1.0, indicating that the distributor should claim in its TRC calculation all of the benefits associated with the CDM program.

The following discussion illustrates three cases where attribution may be an issue.

Case 1- Programs delivered jointly by distributors with single energy savings (i.e. electricity):

In this case, several distributors work together to market and deliver a CDM program. Each participating distributor is allowed to claim the benefits associated with the program (electricity and water) in their service area. The determining factors are the location of the participants and the benefits associated with the program. Therefore, in this case, the Attributable Savings would be:

Attributable Savings = (UATES) x (NUD_{SA}) x (1-FRR) x (AR)

NUD_{SA} - number of units delivered in a distributor's service area.

AR = 1

Case 2 – Multi energy savings in cross sector (gas and electricity) jointly delivered CDM programs:

In this case, a gas and electric distributor jointly market and deliver a CDM program. Each participating distributor is allowed to claim all of the benefits associated with the energy type they distribute (i.e. gas distributors would claim the gas savings and electricity distributors would claim the electricity demand and energy savings) in their service area. Other benefits, such as water savings, need to be allocated between the gas and electric distributor partners proportionally based on the dollar value of gas and electric TRC savings (i.e. where electricity savings represent 60% of the TRC savings of a program, the electric distributor will claim 60% of the water savings).

Case 3 - Multi energy savings in individually delivered CDM programs:

In this case, a distributor works independently to market and deliver a CDM program. The distributor's program may have energy savings additional to the primary energy savings targeted by the program. Common examples of these are Low Flow Shower Head and Programmable Thermostat programs. In these cases, the benefits of the programs will be electricity and other resource savings (i.e. gas and water). As in Case 1, the savings formula would be:

Attributable Savings = (UATES) x (NUD) x (1-FRR) x (AR)

Where UATES incorporate the savings of other energy sources.

3.0 How To Calculate TRC

This section provides details of how to perform a TRC analysis with examples for a single technology calculation, a program calculation and a portfolio calculation.

A distributor's CDM portfolio is the highest level envelope incorporating all of the costs not captured at the technology and program level. Therefore, a CDM portfolio consists of set of cost effective CDM programs. Similarly, a CDM program is designed around a given cost effective measure or technology. For a measure to be considered cost effective, it must have TRC Net Benefits greater than $0.[2] For a measure to be considered cost effective, it must have TRC Net Benefits greater than $0.

Cost effectiveness screening is assessed at each level of a distributor's CDM initiative.

The TRC calculation relies on estimates of:

- avoided cost;
- demand and energy savings;
- equipment cost;
- distributor program costs;
- equipment life;
- free ridership.

These estimates are used in a standard net present value ("NPV") calculation that relies on a discount rate to express a value for future streams of money and to determine a cost effectiveness result in current dollars.

3.1 Technology Screening Analysis

In its simplest form, the single technology screening analysis calculates the cost effectiveness of a single piece of equipment or technology based purely on its energy efficiency characteristics, its cost and equipment life. This screening analysis is the initial step in considering technologies for inclusion in a CDM program.

To perform the technology screening analysis, the required elements are:

- estimate of per unit savings (kW and kWh) by period;
- estimate of equipment cost; and
- expected equipment life.

This is a simple benefit-cost analysis of the technology on a single unit basis.

Calculating the benefits: The benefits are expressed as the product of the per unit savings (in kW and/or kWh) and the avoided costs. This calculation is done for every year of the life of the equipment. These values are then discounted and summed to express the benefits as a single $NPV_{benefits}$.

[2] Distributors may undertake programming on non-cost effective technologies in the form of pilot programs. The Board's guidelines for pilot programs are set out in section 2.1.2 of the draft Guidelines.

Calculating the costs: The equipment cost is the cost of the technology, expressed as either its full or incremental cost. In most cases, the cost of the technology is incurred at the beginning of the initiative and no further costs are incurred over the life of the equipment (i.e. a CFL bulb). However, where the energy efficient equipment has ongoing maintenance costs incremental to the base case alternative, these costs should be included in the analysis and discounted appropriately. Once this calculation is performed, it is expressed as a single NPV_{costs}.

Detailed examples are set out below.

Technology Example 1: ***A 15 Watt Compact Fluorescent Bulb Replacing a 60 Watt Incandescent Bulb***

Step One – Calculating TRC Benefits

TRC benefits represent a discounted stream of electricity avoided costs, other fuel avoided costs (where other fuel savings exist), avoided participant costs and tax benefits. In practice, avoided participant costs and tax benefits are rarely used. The duration of this stream of avoided costs is determined by the life of the technology. In the case of a 15 W compact fluorescent bulb, the measure life is assumed to be 4 years; therefore the benefits accrue over the 4 year period and are discounted to current net present value (using the prescribed discount rate).

The prescribed savings for a 15 watt compact fluorescent bulb, the assumed electricity energy and demand savings and other technology inputs are shown in the tables below:

Table 4.1 Unit Electricity Energy and Demand Savings

	TRC INPUTS								
	Unit Electricity Savings								
	Electricity Savings								
	Winter			Summer			Shoulder		
Technology	On Peak kWh	Mid Peak kWh	Off Peak kWh	On Peak kWh	Mid Peak kWh	Off Peak kWh	Mid Peak kWh	Off Peak kWh	Peak Demand Savings (Summer kW)
15 W CFL	15.5	7.7	20.3	0.0	11.7	14.0	17.5	17.7	0.000

Table 4.2 Other Technology Inputs Required for Calculating TRC Benefits[3]

	TRC INPUTS						
	Technology Information		Other Fuel Savings/Increases				
Technology	Measure Life	Customer Unit Incremental Costs	Unit Annual Gas Savings m3	Unit Water Savings m3 (000's litres)	Unit Propane Savings m3 (000's litres)	Unit Oil Savings litres	Unit Diesel Savings m3
15 W CFL	4	$2.00	0.00	0.00	0.00	0.00	0.00

[3] Note that free ridership is taken into account at the TRC program evaluation level.

The value of the electricity avoided cost savings are calculated by multiplying unit energy and demand savings in Table 4.1 by the appropriate set of avoided supply costs savings shown in Tables 4.3 and 4.4.

Table 4.3 Electricity Avoided Energy Savings

Year	Ontario Seasonal Average Avoided Costs $/kWh							
	Winter			Summer			Shoulder	
	On Peak	Mid Peak	Off Peak	On Peak	Mid Peak	Off Peak	Mid Peak	Off Peak
2007	$ 0.1246	$ 0.0843	$ 0.0452	$ 0.1115	$ 0.0796	$ 0.0459	$ 0.0814	$ 0.0408
2008	$ 0.1154	$ 0.0868	$ 0.0489	$ 0.1106	$ 0.0836	$ 0.0501	$ 0.0904	$ 0.0449
2009	$ 0.1119	$ 0.0771	$ 0.0489	$ 0.1045	$ 0.0795	$ 0.0476	$ 0.0858	$ 0.0434
2010	$ 0.1135	$ 0.0774	$ 0.0521	$ 0.1070	$ 0.0805	$ 0.0482	$ 0.0835	$ 0.0434
2011	$ 0.1102	$ 0.0773	$ 0.0527	$ 0.1032	$ 0.0813	$ 0.0485	$ 0.0842	$ 0.0430
2012	$ 0.1124	$ 0.0789	$ 0.0533	$ 0.1131	$ 0.0846	$ 0.0512	$ 0.0885	$ 0.0478
2013	$ 0.1252	$ 0.0864	$ 0.0599	$ 0.1169	$ 0.0913	$ 0.0540	$ 0.0925	$ 0.0519
2014	$ 0.1257	$ 0.0924	$ 0.0628	$ 0.1279	$ 0.0968	$ 0.0567	$ 0.0989	$ 0.0544
2015	$ 0.1274	$ 0.0947	$ 0.0696	$ 0.1516	$ 0.1067	$ 0.0625	$ 0.1028	$ 0.0599
2016	$ 0.1317	$ 0.0973	$ 0.0709	$ 0.1525	$ 0.1081	$ 0.0639	$ 0.1045	$ 0.0614
2017	$ 0.1360	$ 0.1000	$ 0.0721	$ 0.1535	$ 0.1095	$ 0.0653	$ 0.1062	$ 0.0628
2018	$ 0.1403	$ 0.1027	$ 0.0734	$ 0.1544	$ 0.1109	$ 0.0668	$ 0.1080	$ 0.0643
2019	$ 0.1446	$ 0.1054	$ 0.0746	$ 0.1553	$ 0.1123	$ 0.0682	$ 0.1097	$ 0.0657
2020	$ 0.1489	$ 0.1081	$ 0.0759	$ 0.1563	$ 0.1136	$ 0.0696	$ 0.1114	$ 0.0672
2021	$ 0.1524	$ 0.1104	$ 0.0780	$ 0.1571	$ 0.1165	$ 0.0715	$ 0.1147	$ 0.0691
2022	$ 0.1558	$ 0.1127	$ 0.0800	$ 0.1579	$ 0.1194	$ 0.0734	$ 0.1179	$ 0.0710
2023	$ 0.1593	$ 0.1150	$ 0.0821	$ 0.1587	$ 0.1224	$ 0.0753	$ 0.1211	$ 0.0729
2024	$ 0.1627	$ 0.1173	$ 0.0842	$ 0.1595	$ 0.1253	$ 0.0772	$ 0.1243	$ 0.0748
2025	$ 0.1661	$ 0.1197	$ 0.0863	$ 0.1603	$ 0.1282	$ 0.0791	$ 0.1275	$ 0.0767

Table 4.4 Electricity Avoided Demand Savings

Year	Ontario Seasonal Average Avoided Costs $/kW	
	Generation Capacity	Transmission Capacity
2007	$ -	$ -
2008	$ 74.65	$ 5.62
2009	$ 83.57	$ 5.76
2010	$ 71.49	$ 5.90
2011	$ 85.42	$ 6.05
2012	$ 81.20	$ 6.20
2013	$ 61.60	$ 6.36
2014	$ 46.63	$ 6.52
2015	$ 23.16	$ 6.68
2016	$ 26.88	$ 6.85
2017	$ 29.94	$ 7.02
2018	$ 31.66	$ 7.19
2019	$ 32.41	$ 7.37
2020	$ 31.85	$ 7.56
2021	$ 38.27	$ 7.74
2022	$ 41.97	$ 7.94
2023	$ 44.22	$ 8.14
2024	$ 44.56	$ 8.34
2025	$ 42.02	$ 8.55

Assuming a discount rate of 10%, the detailed calulation of TRC benefits for a 15 watt compact fluorescent bulb are shown below.

TRC Benefits Detailed Calculation

= **Year 1 Avoided Electricity Costs** {(15.5 kWh x $0.124) + (7.7 kWh x $0.0843) + (20.3 kWh x $0.0452) + (0.0 kWh x $0.1115) + (11.7 kWh x $0.0796) + (14.0 kWh x $0.0459) + (17.5 kWh x $0.0814) + (17.7 kWh x $0.0408)} x 1.00 **(discount factor[4])**
+ Year 2 Avoided Electricity Costs {(15.5 kWh x $0.1154) + (7.7 kWh x $0.0868) + (20.3 kWh x $0.0489) + (0.0 kWh x $0.1106) + (11.7 kWh x $0.0836) + (14.0 kWh x $0.0501) + (17.5 kWh x $0.0904) + (17.7 kWh x $0.0449)} x 0.909091 **(discount factor)**
+ Year 3 Avoided Electricity Costs {(15.5 kWh x $0.1119) + (7.7 kWh x $0.0771) + (20.3 kWh x $0.0489) + (0.0 kWh x $0.1045) + (11.7 kWh x $0.0795) + (14.0 kWh x $0.0476) + (17.5 kWh x $0.0858) + (17.7 kWh x $0.0434)} x 0.826446 **(discount factor)**
+ **Year 4 Avoided Electricity Costs** (15.5 kWh x $0.113) + (7.7 kWh x $0.0774) + (20.3 kWh x $0.0521) + (0.0 kWh x $0.107.0) + (11.7 kWh x $0.0805) + (14.0 kWh x $0.0482) + (17.5 kWh x $0.0835) + (17.7 kWh x $0.0434)]} x 0.751315 **(discount factor)**

= $25.43 (Note that this is the sum of the 4 years of discounted results).

Step Two – Calculating TRC Costs

TRC costs represent a discounted stream of increased electricity costs, other fuel costs, participant (customer) and utility costs. In practice, participant costs and utility costs are most commonly applied. In the case of a 15 watt compact fluorescent bulb, there is no increased electricity or other fuel costs. There are however participant costs of $2.00 as shown in Table 4.2. This cost is a one-time cost that occurs in Year 1. As such no discounting is applied.

Step Three – Calculating TRC Net Benefits and Benefit-Cost Ratio

Once TRC benefits and TRC costs have been generated the calculation of TRC net benefits and benefit-cost ratio can be easily derived. The TRC net benefits are simply the difference between the TRC benefits and the TRC costs and the TRC benefit-cost ratio is the TRC benefits divided by TRC costs.

Using the 15 watt compact fluorescent bulb example, the calculation of TRC net benefits and benefit-cost ratio are shown below.

TRC Net Benefits = $25.43 - $2.00 = **$23.43**

TRC Benefit-Cost Ratio = $25.43 / $2.00 = **12.71**

Technology Example 2: *Water Heating Load Shifting – Utility Controlled Relay*

Step One – Calculating TRC Benefits

[4] A discount factor is calculated using the net present value formula [1/(1+discount rate)^$^{(\text{term-1})}$]. For example, using a discount rate of 10%, in year 3 the discount factor is 1/(1.1)^$^{(3-1)}$ = 0.826446

The prescribed savings for a utility controlled relay, the assumed electricity energy and demand savings and other technology inputs are shown in the tables below:

Table 4.5 Unit Electricity Energy and Demand Savings

Technology	TRC INPUTS								
	Unit Electricity Savings								
	Electricity Savings								
	Winter			Summer			Shoulder		
	On Peak kWh	Mid Peak kWh	Off Peak kWh	On Peak kWh	Mid Peak kWh	Off Peak kWh	Mid Peak kWh	Off Peak kWh	Peak Demand Savings (Summer kW)
Utility Controlled Relay	1133.9	-1133.9	0.0	647.9	-427.0	-220.0	0.0	0.0	0.777

Table 4.6 Other Technology Inputs Required for Calculating TRC Benefits

Technology	TRC INPUTS						
	Technology Information		Unit Energy Savings				
	Measure Life	Customer Unit Incremental Costs	Unit Annual Gas Savings m3	Unit Water Savings m3 (000's litres)	Unit Propane Savings m3 (000's litres)	Unit Oil Savings litres	Unit Diesel Savings m3
Utility Controlled Relay	12	$50.00	0.00	0.00	0.00	0.00	0.00

Assuming a discount rate of 10%, the detailed calulation of TRC benefits for a utility controlled relay are shown below.

TRC Benefits Detailed Calculation

= **Year 1 Avoided Electricity Costs** {(1133.9 kWh x $0.124) + (-1133.9 kWh x $0.0843) + (0.0 kWh x $0.0452) + (647.9 kWh x $0.1115) + (-427.0 kWh x $0.0796) + (-220.0 kWh x $0.0459) + (0.0 kWh x $0.0814) + (0.0 kWh x $0.0408) + (0.777 kW x $0.00) + (0.777 kW x $0.00)} x 1.00 (discount factor)
+ Year 2 Avoided Electricity Costs {(1133.9 kWh x $0.1154) + (-1133.9 kWh x $0.0868) + (0.0 kWh x $0.0489) + (647.9 kWh x $0.1106) + (-427.0 kWh x $0.0836) + (-220.0 kWh x $0.0501) + (0.0 kWh x $0.0904) + (0.0 kWh x $0.0449) + (0.777 kW x $74.65) + (0.777 kW x $5.62)} x 0.909091 (discount factor)
+ Year 3 Avoided Electricity Costs {(1133.9 kWh x $0.1119) + (-1133.9 kWh x $0.0771) + (0.0 kWh x $0.0489) + (647.9 kWh x $0.1045) + (-427.0 kWh x $0.0795) + (-220.0 kWh x $0.0476) + (0.0 kWh x $0.0858) + (0.0 kWh x $0.0434) + (0.777 kW x $83.57) + (0.777 kW x $5.76)} x 0.826446 (discount factor)
+ **Year 4 Avoided Electricity Costs** {(1133.9 kWh x $0.1135) + (-1133.9 kWh x $0.0774) + (0.0 kWh x $0.0521) + (647.9 kWh x $0.1070) + (-427.0 kWh x $0.0805) + (-220.0 kWh x $0.0482) + (0.0 kWh x $0.0835) + (0.0 kWh x $0.0434) + (0.777 kW x $71.49) + (0.777 kW x $5.90)} x 0.751315 (discount factor)
+ **Year 5 Avoided Electricity Costs** {(1133.9 kWh x $0.1102) + (-1133.9 kWh x $0.0773) + (0.0 kWh x $0.0527) + (647.9 kWh x $0.1032) + (-427.0 kWh x $0.0813) + (-220.0 kWh x $0.0485) + (0.0 kWh x $0.0842) + (0.0 kWh x $0.0430) + (0.777 kW x $85.42) + (0.777 kW x $6.05)} x 0.683013 (discount factor) + **Year 6 Avoided Electricity Costs** {(1133.9 kWh x $0.1124) + (-1133.9 kWh x $0.0789) + (0.0 kWh x $0.0533) + (647.9 kWh x $0.1131) + (-427.0 kWh x $0.0846) + (-220.0 kWh x $0.0512) + (0.0 kWh x $0.0885) + (0.0 kWh x $0.0478) + (0.777 kW x $81.20) + (0.777 kW x $6.20)} x 0.620921 (discount factor)
+ **Year 7 Avoided Electricity Costs** {(1133.9 kWh x $0.1252) + (-1133.9 kWh x $0.0864) + (0.0 kWh x $0.0599) + (647.9 kWh x $0.1169) + (-427.0 kWh x $0.0913) + (-220.0 kWh x $0.0540) + (0.0 kWh x $0.0925) + (0.0 kWh x $0.0519) + (0.777 kW x $61.60) + (0.777 kW x $6.36)} x 0.564474 (discount factor)

+ **Year 8 Avoided Electricity Costs** {(1133.9 kWh x $0.1257) + (-1133.9 kWh x $0.0924) + (0.0 kWh x $0.0628) + (647.9 kWh x $0.1279) + (-427.0 kWh x $0.0968) + (-220.0 kWh x $0.0567) + (0.0 kWh x $0.0989) + (0.0 kWh x $0.0544) + (0.777 kW x $46.63) + (0.777 kW x $6.52)} x 0.513158 (discount factor)
+ **Year 9 Avoided Electricity Costs** {(1133.9 kWh x $0.1274) + (-1133.9 kWh x $0.0947) + (0.0 kWh x $0.0696) + (647.9 kWh x $0.1516) + (-427.0 kWh x $0.1067) + (-220.0 kWh x $0.0625) + (0.0 kWh x $0.1028) + (0.0 kWh x $0.0599) + (0.777 kW x $23.16) + (0.777 kW x $6.68)} x 0.466507 (discount factor)
+ **Year 10 Avoided Electricity Costs** {(1133.9 kWh x $0.1317) + (-1133.9 kWh x $0.0973) + (0.0 kWh x $0.0709) + (647.9 kWh x $0.1525) + (-427.0 kWh x $0.1081) + (-220.0 kWh x $0.0639) + (0.0 kWh x $0.1045) + (0.0 kWh x $0.0614) + (0.777 kW x $26.88) + (0.777 kW x $6.85)} x 0.424098 (discount factor)
+ **Year 11 Avoided Electricity Costs** {(1133.9 kWh x $0.1360) + (-1133.9 kWh x $0.1000) + (0.0 kWh x $0.0721) + (647.9 kWh x $0.1535) + (-427.0 kWh x $0.1095) + (-220.0 kWh x $0.0653) + (0.0 kWh x $0.1062) + (0.0 kWh x $0.0628) + (0.777 kW x $29.94) + (0.777 kW x $7.02)} x 0.385543 (discount factor)
+ **Year 12 Avoided Electricity Costs** {(1133.9 kWh x $0.1403) + (-1133.9 kWh x $0.1027) + (0.0 kWh x $0.0734) + (647.9 kWh x $0.1544) + (-427.0 kWh x $0.1109) + (-220.0 kWh x $0.0668) + (0.0 kWh x $0.1080) + (0.0 kWh x $0.0643) + (0.777 kW x $31.66) + (0.777 kW x $7.19)} x 0.350494 (discount factor)

= $884.63 (Note that this is the sum of the 12 years of discounted results).

Step Two – Calculating TRC Costs

In the case of a utility controlled relay, there is no increased electricity or other fuel costs. There are however participant costs of $50.00 as shown in Table 4.6.[5] This cost is a one-time cost that occurs in Year 1. As such no discounting is applied.

Step Three – Calculating TRC Net Benefit and Benefit-Cost Ratio

TRC Net Benefits = $884.63 - $50.00 = **$834.63**

TRC Benefit-Cost Ratio = $884.63 / $50.00 = **17.69**

Technology Example 3: ***Energy Efficient Showerhead***

Step One – Calculating TRC Benefits

The prescribed savings for an efficient showerhead, the assumed electricity energy and demand savings and other technology inputs are shown in the tables below:

Table 4.7 Unit Electricity Energy and Demand Savings

	TRC INPUTS								
	Unit Electricity Savings								
	Electricity Savings								
	Winter			Summer			Shoulder		
Technology	On Peak kWh	Mid Peak kWh	Off Peak kWh	On Peak kWh	Mid Peak kWh	Off Peak kWh	Mid Peak kWh	Off Peak kWh	Peak Demand Savings (Summer kW)
Efficient Showerhead	37.5	42.8	100.5	32.5	48.8	101.1	81.3	101.1	0.039

[5] Note that many distributors are now offering utility controlled relays for water heaters. These units may have a cost different to that prescribed by the Board's Assumptions and Measures List. In these cases, it is appropriate to use the "real cost" in the TRC assessment.

Table 4.8 Other Technology Inputs Required for Calculating TRC Benefits

Technology	TRC INPUTS						
	Technology Information		Unit Energy Savings				
	Measure Life	Customer Unit Incremental Costs	Unit Annual Gas Savings m3	Unit Water Savings m3 (000's litres)	Unit Propane Savings m3 (000's litres)	Unit Oil Savings litres	Unit Diesel Savings m3
Efficient Showerhead	12	$7.00	0.00	26.80	0.00	0.00	0.00

Assuming a discount rate of 10%, the detailed calulation of TRC benefits for an efficient showerhead are shown below.

TRC Benefits Detailed Calculation

a) Electricity Savings

= **Year 1 Avoided Electricity Costs** {(37.5 kWh x $0.124) + (42.8 kWh x $0.0843) + (100.5 kWh x $0.0452) + (32.5 kWh x $0.1115) + (48.8 kWh x $0.0796) + (101.1 kWh x $0.0459) + (83.3 kWh x $0.0814) + (101.1 kWh x $0.0408) + (0.039 kW x $0.00) + (0.039 kW x $0.00)} x 1.00 (discount factor)
+ Year 2 Avoided Electricity Costs {(37.5 kWh x $0.1154) + (42.8 kWh x $0.0868) + (100.5 kWh x $0.0489) + (32.5 kWh x $0.1106) + (48.8 kWh x $0.0836) + (101.1 kWh x $0.0501) + (83.3 kWh x $0.0904) + (101.1 kWh x $0.0449) + (0.039 kW x $74.65) + (0.039 kW x $5.62)} x 0.909091 (discount factor)
+ Year 3 Avoided Electricity Costs {(37.5 kWh x $0.1119) + (42.8 kWh x $0.0771) + (100.5 kWh x $0.0489) + (32.5 kWh x $0.1045) + (48.8 kWh x $0.0795) + (101.1 kWh x $0.0476) + (83.3 kWh x $0.0858) + (101.1 kWh x $0.0434) + (0.039 kW x $83.57) + (0.039 kW x $5.76)} x 0.826446 (discount factor)
+ **Year 4 Avoided Electricity Costs** {(37.5 kWh x $0.1135) + (42.8 kWh x $0.0774) + (100.5 kWh x $0.0521) + (101.1 kWh x $0.1070) + (48.8 kWh x $0.0805) + (101.1 kWh x $0.0482) + (83.3 kWh x $0.0835) + (101.1 kWh x $0.0434) + (0.039 kW x $71.49) + (0.039 kW x $5.90)} x 0.751315 (discount factor)
+ **Year 5 Avoided Electricity Costs** {(37.5 kWh x $0.1102) + (42.8 kWh x $0.0773) + (100.5 kWh x $0.0527) + (101.1 kWh x $0.1032) + (48.8 kWh x $0.0813) + (101.1 kWh x $0.0485) + (83.3 kWh x $0.0842) + (101.1 kWh x $0.0430) + (0.039 kW x $85.42) + (0.039 kW x $6.05)} x 0.683013 (discount factor)
+ **Year 6 Avoided Electricity Costs** {(37.5 kWh x $0.1124) + (42.8 kWh x $0.0789) + (100.5 kWh x $0.0533) + (101.1 kWh x $0.1131) + (48.8 kWh x $0.0846) + (101.1 kWh x $0.0512) + (83.3 kWh x $0.0885) + (101.1 kWh x $0.0478) + (0.039 kW x $81.20) + (0.039 kW x $6.20)} x 0.620921 (discount factor)
+ **Year 7 Avoided Electricity Costs** {(37.5 kWh x $0.1252) + (42.8 kWh x $0.0864) + (100.5 kWh x $0.0599) + (101.1 kWh x $0.1169) + (48.8 kWh x $0.0913) + (101.1 kWh x $0.0540) + (83.3 kWh x $0.0925) + (101.1 kWh x $0.0519) + (0.039 kW x $61.60) + (0.039 kW x $6.36)} x 0.564474 (discount factor)
+ **Year 8 Avoided Electricity Costs** {(37.5 kWh x $0.1257) + (42.8 kWh x $0.0924) + (100.5 kWh x $0.0628) + (101.1 kWh x $0.1279) + (48.8 kWh x $0.0968) + (101.1 kWh x $0.0567) + (83.3 kWh x $0.0989) + (101.1 kWh x $0.0544) + (0.039 kW x $46.63) + (0.039 kW x $6.52)} x 0.513158 (discount factor)
+ **Year 9 Avoided Electricity Costs** {(37.5 kWh x $0.1274) + (42.8 kWh x $0.0947) + (100.5 kWh x $0.0696) + (101.1 kWh x $0.1516) + (48.8 kWh x $0.1067) + (101.1 kWh x $0.0625) + (83.3 kWh x $0.1028) + (101.1 kWh x $0.0599) + (0.039 kW x $23.16) + (0.039 kW x $6.68)} x 0.466507 (discount factor)
+ **Year 10 Avoided Electricity Costs** {(37.5 kWh x $0.1317) + (42.8 kWh x $0.0973) + (100.5 kWh x $0.0709) + (32.5 kWh x $0.1525) + (48.8 kWh x $0.1081) + (101.1 kWh x $0.0639) + (83.3 kWh x $0.1045) + (101.1 kWh x $0.0614) + (0.039 kW x $26.88) + (0.039 kW x $6.85)} x 0.424098 (discount factor)
+ **Year 11 Avoided Electricity Costs** {(37.5 kWh x $0.1360) + (42.8 kWh x $0.1000) + (100.5 kWh x $0.0721) + (32.5 kWh x $0.1535) + (48.8 kWh x $0.1095) + (101.1 kWh x $0.0653) + (83.3 kWh x $0.1062) + (101.1 kWh x $0.0628) + (0.039 kW x $29.94) + (0.039 kW x $7.02)} x 0.385543 (discount factor)
+ **Year 12 Avoided Electricity Costs** {(37.5 kWh x $0.1403) + (42.8 kWh x $0.1027) + (100.5 kWh x $0.0734) + (32.5 kWh x $0.1544) + (48.8 kWh x $0.1109) + (101.1 kWh x $0.0668) + (83.3 kWh x $0.1080) + (101.1 kWh x $0.0643) + (0.039 kW x $31.66) + (0.039 kW x $7.19)} x 0.350494 (discount factor)

= $ 317.14 (Note that this is the sum of the 12 years of discounted results).

b) Water Savings

Assuming a water rate of $87.60/m3 in year 2007 and an escalation rate of 2% the avoided water cost are shown in table 4.9.

Table 4.9 Sample Avoided Water Rates

Year	Sample Avoided Water Costs $/m3	
	Water Rate	
2007	$	0.8760
2008	$	0.8935
2009	$	0.9114
2010	$	0.9296
2011	$	0.9482
2012	$	0.9672
2013	$	0.9865
2014	$	1.0062
2015	$	1.0264
2016	$	1.0469
2017	$	1.0678
2018	$	1.0892
2019	$	1.1110
2020	$	1.1332
2021	$	1.1559
2022	$	1.1790
2023	$	1.2026
2024	$	1.2266
2025	$	1.2511

= **Year 1 Avoided Water Costs** 26.8 m3 x $0.8760 x 1.00 (discount factor)
+ Year 2 Avoided Water Costs 26.8 m3 x $0.8935 x 0.909091 (discount factor)
+ Year 3 Avoided Water Costs 26.8 m3 x $0.9114 x 0.826446 (discount factor)
+ Year 4 Avoided Water Costs 26.8 m3 x $0.9296 x 0.751315 (discount factor)
+ **Year 5 Avoided Water Costs** 26.8 m3 x $0.9482 x 0.683013 (discount factor)
+ **Year 6 Avoided Water Costs** 26.8 m3 x $0.9672 x 0.620921 (discount factor)
+ **Year 7 Avoided Water Costs** 26.8 m3 x $1.0062 x 0.564474 (discount factor)
+ **Year 8 Avoided Water Costs** 26.8 m3 x $1.0264 x 0.513158 (discount factor)
+ **Year 9 Avoided Water Costs** 26.8 m3 x $1.0469 x 0.466507 (discount factor)
+ **Year 10 Avoided Water Costs** 26.8 m3 x $1.0678 x 0.424098 (discount factor)
+ **Year 11 Avoided Water Costs** 26.8 m3 x $1.0892 x 0.385543 (discount factor)
+ **Year 12 Avoided Water Costs** 26.8 m3 x $1.1110 x 0.350494 (discount factor)

= $ 190.60 (Note that this is the sum of the 12 years of discounted results).

Total TRC Benefits = Avoided Electricity Costs + Avoided Water Costs
= $ 317.14 + $190.60
= $ 507.74

Step Two – Calculating TRC Costs

In the case of an energy efficient showerhead, there is no increased electricity or other fuel costs. There are however participant costs of $7.00 as shown in Table 4.8. This cost is a one-time cost that occurs in Year 1. As such no discounting is applied.

Step Three – Calculating TRC Net Benefits and Benefit-Cost Ratio

TRC Net Benefits = $507.74 - $7.00 = **$500.74**

TRC Benefit-Cost Ratio = $507.74 / $7.00 = **72.53**

3.2 Program Screening Analysis

Once a measure has passed the technology screening analysis, the analyst may wish to design a program that uses the technology. The program screening analysis combines the results of the individual technology analysis with the key program components, including number of participants, free ridership rates and direct distributor program costs. The program screening analysis repeats the same approach as defined above with the inclusion of the adjustment factors to assess the measure at the program level.

Detailed examples are set out below.

Program Example 1: ***Residential Energy Audit Campaign***

Using the compact fluorescent bulb and showerhead technologies described earlier, assume a utility has designed a residential energy audit program. The program provides the participant with an energy audit at a cost of $100 and in return the participant receives a report highlighting potential energy saving opportunities along with two free 15 watt CFLs and an energy efficient showerhead.

The utility is expecting 100 participants in the first year. Given the program design, free ridership is expected to be 10%. This means that 10% of the participants would have undertaken an energy audit on their own in the absence of the program. The utility's cost for running the program is estimated at $30,000, which includes the cost of designing, marketing, operating and evaluating the program, as well as the cost of the CFL bulbs and showerheads provided to the customer.[6]

Tables 4.10 and 4.11 provide the key inputs required for undertaking the TRC test, including per unit savings, number of participants, free ridership, measure life, customer equipment cost and alternative resource savings. Program costs of $30,000 are shown as a single line item.

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[6] While CFLs and showerheads are most often installed by the participant and not the utility, according to the TAG™ Technical Assessment Guide Volume 4 Revision: Fundamentals and Methods, End Use, Prepared by Barakat and Chamberlin Inc., January 1991, a distributor can often use its volume-buying capacity to receive measures at reduced costs.

Table 4.10 Program Electricity Energy and Demand Savings

Technology	TRC INPUTS								
	Unit Electricity Savings								
	Electricity Savings								
	Winter			Summer			Shoulder		
	On Peak kWh	Mid Peak kWh	Off Peak kWh	On Peak kWh	Mid Peak kWh	Off Peak kWh	Mid Peak kWh	Off Peak kWh	Peak Demand Savings (Summer kW)
Energy Audit	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.000
15 W CFL	15.5	7.7	20.3	0.0	11.7	14.0	17.5	17.7	0.000
Efficient Showerhead	37.5	42.8	100.5	32.5	48.8	101.1	81.3	101.1	0.039
Program Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.000

Table 4.11 Other Program Inputs Required for Calculating TRC Benefits

Technology	TRC INPUTS									
	Technology Information					Unit Energy Savings				
	Participants [gross]	Free Ridership %	Measure Life	Customer Unit Incremental Costs	Program Delivery Costs	Unit Annual Gas Savings m3	Unit Water Savings m3 (000's litres)	Unit Propane Savings m3 (000's litres)	Unit Oil Savings litres	Unit Diesel Savings m3
Energy Audit	100	10.0%	0	$100.00	$ -	0.00	0.00	0.00	0.00	0.00
15 W CFL	200	10.0%	4	$0.00	$ -	0.00	0.00	0.00	0.00	0.00
Efficient Showerhead	100	10.0%	12	$0.00	$ -	0.00	26.80	0.00	0.00	0.00
Program Costs	-	0.0%	0	$0.00	$ 30,000.00	0.00	0.00	0.00	0.00	0.00

Step One – Calculating TRC Benefits

Energy Audit TRC Benefits = $0

15 Watt CFL TRC Benefits[7] = $ 25.43 x 200 bulbs x (1-freeridership)
= $ 4,577.40

Efficient Showerhead TRC Benefits[8] = $ 507.74 x 100 showerheads x (1-freeridership)
= $ 45,696.60

Total Program TRC Benefits = $ 4,577.40 + $ 45,696.60
= $ 50,274

Step Two – Calculating TRC Costs

a. Customer Equipment Costs

Energy Audit TRC Costs = $100 x 100 audits x (1-freeridership)
= $9,000

15 Watt CFL TRC Costs[9] = $ 0 x 200 bulbs x (1-freeridership)
= $ 0

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[7] See calculating TRC benefits in technology example 1.
[8] See calculating TRC benefits in technology example 3.
[9] Utility is giving away CFLs. Costs of bulbs are included in program costs.

Efficient Showerhead TRC Costs[10] = $ 0 x 100 x (1-freeridership)
= $ 0

Program Costs = $ 30,000

Total Program TRC Costs = $ 9,000 + $30,000
= $ 39,000

Step Three – Calculating TRC Net Benefits and Benefit-Cost Ratio

TRC Net Benefits = $50,274 - $39,000 = **$11,274**

TRC Benefit-Cost Ratio = $50,274/ $39,000 = **1.29**

Program Example 2: *Residential Demand Response Program*

Using the utility controlled relay unit described earlier, assume a utility has designed a residential demand response program. The program encourages participants to install a utility controlled relay on their water heater. In exchange for participating in the program the participant receives a $25 voucher or coupon.

The utility expects 1,000 participants to enroll in the first year. The utility believes that in the absence of the program no customers would install the unit and therefore assumes a program free ridership rate of 0%. The utility's cost for operating the program is assumed to be $475,000 which includes: equipment and installation; control systems; a $25 gift card: and program marketing and administration. Note that for the purposes of this analysis, the cost of the equipment is included in the program costs; as such customer equipment costs are reported as $0 in the TRC test. In practice, from the perspective of the TRC test it does not matter if the equipment costs are calculated as customer equipment costs, or included as program costs, as long as they are properly accounted for.[11]

Tables 4.12 and 4.13 provide the key inputs required for undertaking the TRC test, including per unit savings, number of participants, free ridership, measure life, customer equipment cost and alternative resource savings. Program costs of $475,000 are shown as a single line item.

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[10] Utility is giving away showerheads. Costs of showerheads are included in program costs.

[11] According to the TAG™ Technical Assessment Guide Volume 4 Revision: Fundamentals and Methods, End Use, Prepared by Barakat and Chamberlin Inc., January 1991, utility equipment costs include the cost of any utility devices needed to operate the program as well as any CDM measure directly installed by the utility. Programs most often requiring utility expenditure for CDM measures are load management programs such as a direct load control.

Table 4.12 Program Electricity Energy and Demand Savings

Technology	TRC INPUTS								
	Unit Electricity Savings								
	Electricity Savings								
	Winter			Summer			Shoulder		
	On Peak kWh	Mid Peak kWh	Off Peak kWh	On Peak kWh	Mid Peak kWh	Off Peak kWh	Mid Peak kWh	Off Peak kWh	Peak Demand Savings (Summer kW)
Utility Controlled Relay	1133.9	-1133.9	0.0	647.9	-427.0	-220.0	0.0	0.0	0.777
Program Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.000

Table 4.13 Other Program Inputs Required for Calculating TRC Benefits

Technology	TRC INPUTS									
	Technology Information					Unit Energy Savings				
	Participants [gross]	Free Ridership %	Measure Life	Customer Unit Incremental Costs	Program Delivery Costs	Unit Annual Gas Savings m3	Unit Water Savings m3 (000's litres)	Unit Propane Savings m3 (000's litres)	Unit Oil Savings litres	Unit Diesel Savings m3
Utility Controlled Relay	1,000	0.0%	12	$0.00	$ -	0.00	0.00	0.00	0.00	0.00
Program Costs	-	0.0%	0	$0.00	$ 475,000.00	0.00	0.00	0.00	0.00	0.00

Step One – Calculating TRC Benefits

Utility Controlled Relay Unit TRC Benefits[12] = $884.63 x 1,000 units x (1- freeridership)
= $ 884,630

Step Two – Calculating TRC Costs

b. Customer Equipment Costs

Utility Controlled Relay TRC Costs[13] = $ 0 x 1,000 units x (1-freeridership)
= $ 0

Program Costs = $ 475,000

Total Program TRC Costs = $ 0 + $475,000
= $ 475,000

Step Three – Calculating TRC Net Benefit and Benefit-Cost Ratio

TRC Net Benefits = $884,630 - $475,000 = **$409,630**

TRC Benefit-Cost Ratio = $884,630 / $475,000 = **1.86**

[12] See calculating TRC benefits in technology example 2.
[13] See calculating TRC costs in technology example 2.

3.3 Portfolio Screening Analysis

Once the distributor has screened all of its programs and is comfortable with the program designs, the overall cost effectiveness of the portfolio needs to be tested. To do this, the distributor will sum the program TRC results and then allocate administrative and any indirect costs to the entire portfolio. Administrative costs include overhead, monitoring and evaluation costs and administration costs associated with the delivery of the overall CDM portfolio. This roll-up value represents the TRC result for the entire CDM programming activity.

Portfolio Example: ***Portfolio Screening Analysis***

Assuming a distributor planned to deliver only the two programs outlined above; the following consists of a theoretical portfolio screening analysis.

Assuming a distributor has indirect costs of administration, market support, overhead and monitoring and evaluation of $50,000. The NPV of the portfolio would be as follows:

Program 1 NPV Program:	11,274
Program 2 NPV Program:	409,630
Total Indirect Costs:	(50,000)
NPV_{TRC}	340,904

Therefore, the NPV_{TRC} of this portfolio is $340,904.

3.4 Using TRC Analysis for Post Program Evaluation

The TRC calculation done at the end of a program year follows exactly the same approach using the “actual” information collected as part of the tracking and reporting exercises as opposed to estimates.

4.0 Symbols Used in the TRC Guide

The following is a summary of all of the symbols used in the TRC Guide:

NPV	= net present value
NPV_{TRC}	= net present value of total resource cost calculation
B_{TRC}	= present value of total resource cost benefits
C_{TRC}	= present value of total resource cost costs
AC_t	= avoided resource costs in year t
UC_t	= distributor program costs in year t
PC_t	= participant costs in year t
N	= number of years use in the analysis
d	= discount rate used in the analysis
INC_t	= incentive amount provided by the distributor in year t
UATES	= unit annual total energy savings
NUD	= number of units delivered or installed
NUD_{sa}	= number of units delivered or installed in an distributors service area
FRR	= free rider rate
AR	= attribution rate
AS	= attributable savings
$NPV_{technology}$	= net present value of the technology at the technology screening level
$NPV_{program}$	= net present value of the program

APPENDIX B:

Guidelines for the Application of Fully Allocated Costing

Appendix B - Guidelines for the Application of Fully-Allocated Costing for CDM Activities

1. INTRODUCTION

The Board has determined that a fully allocated costing methodology must be applied to all CDM activities. This Appendix provides information on how distributors should apply a fully allocated costing approach.

A fully allocated costing methodology results in the allocation of direct costs and of a proportional share of indirect costs. This methodology would, for example, include a proportional allocation of employee benefits (e.g. health insurance) for time and efforts spent in relation to CDM activities.

For CDM activities funded by the OPA, the direct costs and the proportional share of the indirect costs attributable to OPA-funded CDM activities should be removed from the distributor's distribution rates, and more appropriately recovered through the distributor's OPA-funded CDM activities. This is necessary to avoid double-counting, since all existing direct and indirect costs are included in distribution rates.

For CDM activities funded through distribution rates, a fully allocated costing approach is also required but costs will continue to be included in distribution rates. The use of fully allocated costing will ensure that programs are cost effective since the full costs incurred to undertake CDM activities are included in the cost-benefit analysis.

2. COST ALLOCATION PROCESS

Fully allocated costs are the sum of ***marginal costs (direct costs)*** and ***allocable costs*** (**or** ***indirect costs***). These costs are defined as follows:

Marginal costs - Those costs which would be eliminated or reduced if the CDM activities as a whole were no longer undertaken.

Allocable costs - Those costs which would be incurred regardless of whether or not the CDM activities were undertaken.

Marginal costs can be directly assigned to CDM activities. Allocable or indirect costs must be allocated, using a cost driver, to determine the proportional share of the indirect costs attributable to CDM activities.

2.1 Activity Analysis

In order to determine the costs associated with CDM activities, distributors should use an activity analysis process to assess the nature and extent of the functions being performed throughout the distribution company to undertake the CDM activities, and the links between these functions and the underlying costs. The link is referred to as a ***cost***

driver. A ***cost driver*** is a measure used to allocate, to a CDM activity, the costs of any functions performed within the distribution company to undertake the CDM activity. The analysis should include the identification of all activities performed within the distribution company, whether or not these activities directly or indirectly support CDM activities. This provides a complete activity profile of the distribution company, thereby providing the basis for a complete and reasonable allocation of costs.

Distributors will need to make a determination on the appropriate level of detail used in the activity analysis. Consideration of the costs associated with a finer activity breakdown in comparison to the benefits to be gained must be made.

2.2 Costs to Include

The activity analysis should include, for the purposes of cost allocation, direct and indirect costs such as:

- All Salaries (including supervisory, weekly, hourly and part time labour costs)
- Employee benefits
- Paid overtime
- Employee expenses
- Billing and Collection
- Community Relations
- Administration and General expenses
- IT costs
- Office and Computer equipment

This list is not an exhaustive. There may be other costs that need to be considered.

The remainder of this document deals with the allocation of allocable or indirect costs.

2.3 Cost Drivers for Allocable Costs

To complete the activity analysis, a distributor must determine an appropriate cost driver for each activity not directly related to CDM.

Cost drivers should be:

- Representative of how costs are being incurred;
- Implemented in a cost effective manner; and
- Understandable.

Generally, the nature of the activities will need to be assessed in order to select an appropriate cost driver. As discussed below, cost drivers include headcount, time, and volume of activity.

2.3.1 Headcount as a Driver

A common cost driver used to allocate salaries and other labour-related costs is headcount. This driver is based on the number of full time equivalents (FTE) needed to support CDM activities. ***FTEs*** are a measure of labour effort devoted to an activity. For example, if six people each devoted 25% of their time to an activity, the full time equivalent for that activity would be 1.5 FTEs. Part time positions need to be converted into full time equivalents. For example, if an employee works 3 days per week, the full time equivalent would be 0.6 FTE. The allocated FTEs provide the basis to allocate employee related costs such as employee benefits, paid overtime, employee expenses, or employee related support activities such as Human Resources.

Activities for which a headcount driver is appropriate also include activities that generally support employees in the performance of their duties and are used equally by each employee. Examples of activities where use of a headcount driver may be appropriate for the determination of fully allocated costs are payroll, IT services, and computer and office equipment.

2.3.2 Time as a Driver

Time can also be used as a cost driver for activities such as executive and administrative functions, legal services, and financial analysis. While these functions may not be directly involved in the day-to-day activities related to CDM, the executive and administrative functions, for example, may oversee, and support, respectively, other functions within the distribution company that are directly involved in CDM activities. These functions generally lend themselves to time reporting as they are typically project specific. The use of time is considered practical and appropriate in these cases since it provides a strong link to the incurrence of costs.

In order to calculate the percentage of time to be allocated to CDM activities, the base hours per employee must be determined. The base hours subject to allocation must include only those hours which can be considered to be available for work, including overtime. This ensures that all the costs of an employee, such as vacation or training days, are equally shared across all hours worked.

2.3.3 Number or Frequency of Activity as a Driver

Some activities can be repetitive in nature and consistent over time in terms of the level of effort required to provide service. Examples of such activities might include payroll processing, customer care, and accounts payable. As such, they can be allocated based on the number of events reflecting or causing the activity to be performed and, therefore, the cost to be incurred.

For example, call centre costs could be allocated based on number of calls received in relation to CDM activities, and accounts payable processing costs could be allocated based on the number of CDM invoices processed.

2.3.4 Composite Ratio as a Driver

A ***composite ratio*** is a cost driver which allocates the cost of an activity on the same basis as the allocation of one or more other activities. A composite ratio is normally used to allocate the cost of an activity which supports other activities.

A composite ratio could be used, for example, to allocate the costs of an administrative or general function which support the entire organization. For instance, if the cost drivers described above result in an allocation of 5% of the total operating, maintenance and administration expenses being allocated to CDM activities, then this ratio could be used to allocate the costs of the administrative or general function.

APPENDIX C:

Input Assumptions Template

Appendix C: Input Assumptions Template

Efficient Technology & Equipment Description
What equipment/technology is being installed?
Base Technology & Equipment Description
What equipment/technology would otherwise have been installed?

Resource Savings Assumptions

Electricity	***kW or kWh***
Description of how electricity savings assumptions where determined.	
Natural Gas	***m^3 or Btu or CFM***
Where applicable. Description of how natural gas savings assumptions where determined.	
Water	***L***
Where applicable. Description of how water savings assumptions where determined.	

Other Input Assumptions

Equipment Life	***years***
What is the estimated service life of the equipment?	
Incremental Cost	***$/kW or $/kWh***
What is the difference in cost between the efficient equipment/technology and the base equipment/technology?	
Free Ridership	***%***
What is the appropriate free ridership rate for a program using this equipment/technology?	