Cost Effectiveness Guide for Energy Efficiency Version 4

Independent Electricity System Operator
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Connecting Today.
Powering Tomorrow.

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Abbreviations

ASC	Avoided supply-side resource costs
BC	Benefit Cost
BS	Bill Savings
CDM	Conservation And Demand Management
DR	Demand Response
Dx	Distribution System
EE	Energy Efficiency
ER	Early Retirement
EUL	Effective Useful Life
FR	Free Ridership
IC	Incentive Costs
IE	Interactive Effects
IESO	Independent Electricity System Operator
IHD	In-Home Display
kW	Kilowatt
kWh	Kilowatt Hour
LC	Levelized Delivery Cost
LLF	Line Loss Factor
LR	Lost Revenue
LUEC	Levelized Unit Energy Cost
MW	Megawatt
MWh	Megawatt Hour
NC	New Construction
NDR	Nominal Discount Rate
NEBs	Non-Energy Benefits
NI	Net Impacts (Peak Demand And Energy Savings)

NPV	Net Present Value
NTGR	Net to Gross Ratio
O&M	Operations And Maintenance
ORB	Other Resource Benefits
PAC	Program Administrator Cost
PC	Participant Cost
PRC	Program Costs
PTC	Net Participant Costs
PV	Present Value
RDR	Real Discount Rate
RE	Rebound Effect
RET	Retrofit
RIM	Rate Impact Measure
ROB	Replace On Burnout
RR	Realization Rate
RUL	Remaining Useful Life
SC	Societal Cost
SO	Spillover
T&D	Transmission And Distribution
TC	Tax Credits
TRC	Total Resource Cost
Tx	Transmission System

1. Introduction

This Cost Effectiveness Guide ("Guide") describes standard industry metrics to assess the cost effectiveness of conservation and demand management (CDM) resources. Cost effectiveness assesses whether the benefits of an investment exceed the costs.

Cost effectiveness metrics include:

- Tests, which are benefit-cost analyses; and,
- Levelized delivery cost metrics, which express the costs per unit of peak demand or energy savings.

Cost effectiveness metrics can be used to assess CDM from both a screening perspective during planning stages and from an evaluation perspective as part of the evaluation, measurement and verification (EM&V) process.

Standard industry cost effectiveness metrics contained in this Guide can be applied differently depending on regulatory and policy frameworks. The National Action Plan for Energy Efficiency's report *Understanding Cost-Effectiveness of Energy Efficiency Programs*, for example, provides a jurisdictional review of cost effectiveness practices and issues in the United States, which readers of this Guide may find useful for additional background information[1].

This Guide is primarily intended to provide detailed guidance on the assessment of Energy Efficiency (EE) resources and is intended to complement, not replace, the policies, concepts, and procedures relating to CDM in Ontario found in the Independent Electricity System Operator's (IESO's) *EM&V Protocols V4.0.*[2]

1 National Action Plan Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers. November 2008. Available at: https://www.epa.gov/sites/production/files/2015-08/documents/cost-effectiveness.pdf

2 Available at: https://www.ieso.ca/en/Sector-Participants/Energy-Efficiency/Evaluation-Measurement-and-Verification

2. Structure of the Guide

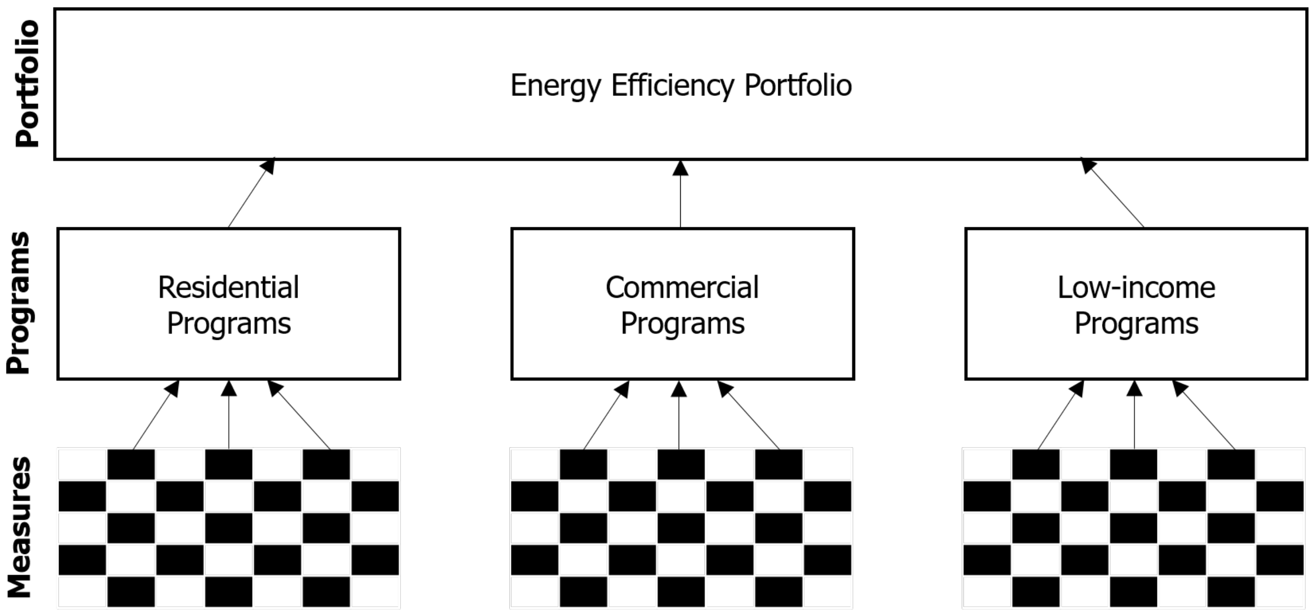
This Guide is structured in the following five key sections:

- **Use of Cost Effectiveness Tests** describes at a high-level how various cost effectiveness tests are used, their inputs, strengths, and weaknesses.
- **Concepts & Components of Cost Effectiveness Tests** is broken down into two sub-sections: concepts and components. The concepts sub-section provides foundational information required to compute the cost effectiveness components. The components section provides detailed instructions to calculate each component used in all cost effectiveness tests.
- **Calculation of Cost Effectiveness Tests** specifies the components used in each metric and how to calculate each metric.
- **Cost Effectiveness Guidelines** discusses important considerations when deriving the inputs and outputs to a cost effectiveness analysis.
- **Special Cases/Examples** provides guidance on the categorization of costs that may be ambiguous or require interpretation.

3. Use of Cost Effectiveness Tests

CDM can be assessed at various levels of detail: measure, program, or portfolio. The measure is the most granular level of CDM and represents the conservation technology, product, or action implemented by a participant. A program is a collection of measures targeted towards, for example, a particular end-use (e.g., lighting) or customer type (e.g., small commercial). A portfolio is a collection of programs. Figure 3.1 | Levels of CDM Implementationoutlines an illustrative example of the levels of CDM implementation.

Figure 3.1 | Levels of CDM Implementation



The use of multiple tests when screening CDM measures, programs or portfolios provides a well-rounded assessment of cost effectiveness. Each metric is used to assess cost effectiveness from a different perspective and can be used for different purposes. Jurisdictions will emphasize specific tests depending on the policy environment and objectives of that particular jurisdiction.

Table 3.1 | Overview of Cost Effectiveness Tests outlines each cost effectiveness test, the key question it answers and a brief summary of the approach. Cost effectiveness tests are comparisons of benefits and costs expressed as both the dollar value of the net benefit (or cost) and as a ratio of benefits to costs. The remainder of this section is split into sub-sections, each describing the tests listed in Table 3.1 | Overview of Cost Effectiveness Tests.

Table 3.1 | Overview of Cost Effectiveness Tests

Cost Effectiveness Tests	Key Question Answered	Summary Approach
Total Resource Cost (TRC) Test	How will the total costs of energy and demand in the utility service territory be affected?	Compares the costs incurred to design and deliver programs and customers' costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, natural gas, etc.)
Societal Cost (SC) Test	Is the utility, province or nation better off as a whole?	Identical to TRC approach, but also includes the cost of "externalities" (e.g., greenhouse gas emissions, health costs, etc.)
Program Administrator Cost (PAC) Test	How will utility costs be affected?	Compares the costs incurred to design and deliver programs by the program administrator with avoided electricity supply-side resource costs[3]
Ratepayer Impact Measure (RIM) Test	How will utility rates be affected?	Compares administrator costs and utility bill reductions with avoided electricity and other supply-side resource costs
Participant Cost (PC) Test	Will the participant benefit over the measure life?	Compares the costs and benefits of the customer installing the measure
Levelized Delivery Cost (LC) Metric	What is the per-unit cost to the utility?	Normalizes the costs incurred to design and deliver programs per unit saved (i.e., peak demand or energy savings)

3.1 Total Resource Cost (TRC)

Description & Perspective: The TRC test compares the costs incurred to design and deliver programs and customers' costs with the avoided electricity and other supply-side resource costs (generation, transmission, natural gas, etc.).

Inputs:

Costs:

- The expenses incurred by a program administrator to design and deliver CDM.

3 The IESO, as the program administrator, would use avoided electricity supply-side resource costs. If a utility is responsible for electricity and natural gas resources, both of these benefits and costs would be included.

- The incremental expenses incurred by participants to implement the conservation action.

Incentives provided to participants from the program administrator to encourage participation in CDM programs are *not* included in the TRC test as these are simply a transfer from the program administrator to participating customers.

Benefits:

- The electricity system related costs that are no longer required as a result of the savings achieved by CDM, including:
  - Generation costs;
  - Transmission and distribution (T&D) costs;
  - Fuel costs; and,
  - Operations and maintenance (O&M) costs.
- Other avoided supply-side resource costs (e.g., natural gas).
- Non-resource or non-energy benefits such as avoided greenhouse gas emissions, reduced water consumption or improved water quality, and avoided health costs.[4]

Strengths: The strength of a TRC test is that it provides a holistic viewpoint, by considering costs incurred by, and benefits that accrue to, both the utility and the participant.

Weaknesses: The TRC test does not consider the effects of revenue reduction and other non-energy benefits.

For more information regarding the comparison of CDM resources to supply resources, please refer to Section 6.3 Comparing Supply-Side Resources

3.2 Societal Cost (SC) Test

Description & Perspective: The SC test is identical to the TRC approach, but also includes the cost of "externalities," for example, increased comfort, environmental improvements (i.e., reductions in greenhouse gas emissions, better air/water quality), reduction in health costs/improved health, and public/national security. The SC can also be referred to as an extended TRC test.

Inputs:

Costs:

- Same as the TRC test.

Benefits:

- Same as the TRC test.

4 See Section 4.2.7 Non-Energy Benefits (NEBs)/Externalities

- Non-resource or non-energy benefits such as avoided greenhouse gas emissions, reduced water consumption or improved water quality, and avoided health costs.
- Some jurisdictions apply a lower discount rate or adder to the benefits to account for the greater uncertainty associated with non-resource and non-energy CDM benefits.

Strengths: The primary strength of the SC test is that, in addition to capturing the direct benefits and costs to the program administrator and participants, it captures both direct and indirect benefits to society as a whole by including the externalities mentioned above.

Weaknesses: However, the scope of indirect costs and benefits may be too broad for some stakeholders and non-energy benefits can be difficult to quantify.

For more information regarding the comparison of CDM resources to supply resources, please refer to Section 6.3 Comparing Supply-Side Resources.

3.3 Program Administrator Cost (PAC) Test

Description & Perspective: The PAC test compares the costs incurred to design and deliver programs by the program administrator with avoided electricity supply-side resource costs[5] from the perspective of the program administrator.

Inputs:

Costs:

- Total expenses incurred by a program administrator to design and deliver CDM.
- The cost of providing incentives provided to participants to entice participation in the program.

Benefits:

- The electricity system related costs that are no longer required as a result of the savings achieved by CDM, including:
  - Generation costs;
  - Transmission and distribution (T&D) costs;
  - Fuel costs; and,
  - Operations and maintenance (O&M) costs.

Strengths: The PAC test does not include an estimate of lost revenue, and therefore is not complicated by uncertainty in rates in the short or long-term.

Weaknesses: It does not capture the participant costs or potential rate impacts of CDM.

5 The IESO, as the program administrator, would use avoided electricity supply-side resource costs. If a utility is responsible for electricity and natural gas resources, both of these benefits and costs would be included.

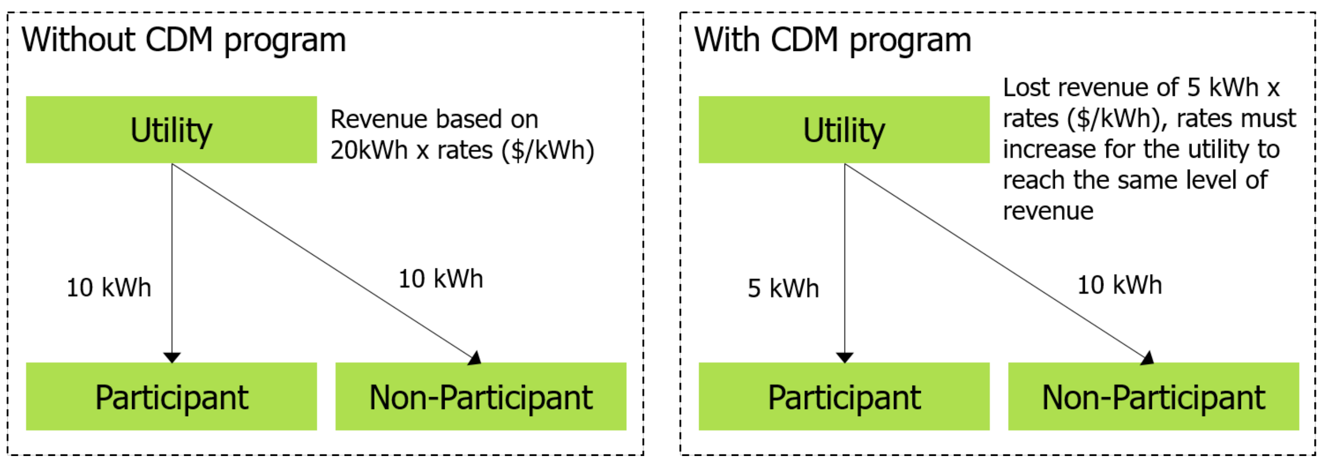
For more information regarding the comparison of CDM resources to supply resources, please refer to Section 6.3 Comparing Supply-Side Resources.

3.4 Ratepayer Impact Measure (RIM) Test

Description & Perspective: The RIM test compares program administrator costs and utility lost revenue with avoided electricity and other supply-side resource costs for all ratepayers due to CDM. The RIM test captures the transfer of costs from participant to non-participants. This transfer of costs occurs due to the utility's need to recover lost revenue (due to conservation) through rates (paid by participants and non-participants alike).

Figure 3.2 | Concept of Lost Revenue to Utility provides a simple illustrative example to demonstrate this concept. For example, without a CDM program, a participant and non-participant using 10 kWh each would result in the utility revenue being based on 20 kWh. With a CDM program, a participant may end up using only 5 kWh while the non-participant is still using 10 kWh. This results in the utility revenue being based on 15 kWh with a CDM program, compared to 20 kWh without a CDM program. Thus, there is lost revenue from energy savings of 5 kWh so rates must increase for the utility to make up for this loss in revenue.

Figure 3.2 | Concept of Lost Revenue to Utility



Inputs:

Costs:

- Utility's lost revenue as a result of customers using less electricity.
- Expenses incurred by a program administrator to design and deliver CDM.
- The cost of providing incentives provided to participants to entice participation in the program.

Benefits:

- The electricity system related costs that are no longer required as a result of the savings achieved by CDM, including:

    - Generation costs;
    - Transmission and distribution (T&D) costs;
    - Fuel costs; and,
    - Operations and maintenance (O&M) costs.
- Other avoided supply-side resource costs (e.g., natural gas).

Strengths: The RIM test captures the cost transfer (as a result of lost revenue) resulting from CDM.

Weaknesses: The RIM test is sensitive to projections of long-term rates and marginal costs, which may be hard to predict. As a result, additional analysis beyond a RIM test may be needed to fully assess impacts to rates and account for the effect of reduced energy demand on longer-term rates and customer bills.

For more information regarding the comparison of CDM resources to supply resources, please refer to Section 6.3 Comparing Supply-Side Resources.

3.5 Participant Cost (PC) Test

Description & Perspective: The PC test compares costs and benefits of CDM from the perspective of the participating customers. The PC test is typically used for informational purposes and to assist with program design and planning. It may be used as an input to support the development of incentive levels.

Inputs:

Costs:

- Additional expenses incurred by participants to implement the conservation action (i.e., the incremental costs of participating).

Benefits:

- Bill savings due to reduced consumption of electricity and other resources (e.g., natural gas, water).
- The cost of providing incentives provided to participants to entice participation in the program.
- Any reductions in O&M costs as a result of the CDM.

Strengths: The PC test is useful for program design, particularly in developing incentive levels and participation goals. The PC test is also helpful to assess the desirability of a program to potential participants.

Weaknesses: The PC test does not fully capture the customer decision-making process since it does not account for customers' qualitative judgments.

For more information regarding the comparison of CDM resources to supply resources, please refer to Section 6.3 Comparing Supply-Side Resources.

3.6 Levelized Delivery Cost (LC) Metric

Description & Perspective: The LC metric normalizes the costs incurred by the program administrator per unit of energy or demand reduced. The levelized delivery cost is also referred to as the "Levelized Unit Energy Cost" (LUEC) when assessing costs per unit of energy savings achieved.

Inputs:

Costs:

- Total expenses incurred by the program administrator to design and deliver CDM.
- The cost of providing incentives provided to participants to entice participation in the program.

Benefits:

- Energy savings over the lifetime of the CDM resource.; or,
- Peak demand reduction over the lifetime of the CDM resource.

Strengths: The LC provides a simple basis for comparing the cost of CDM with the cost of other supply-side resources. Like the PAC the LC is not complicated by uncertainty in rates in the short or long-term.

Weaknesses: The LC only reflects a portion of the full costs of CDM - the rate impacts of CDM are not captured. In addition, this metric considers only the direct electricity system benefits of CDM, peak demand or energy savings, and thus does not fully capture the total value of CDM.

For more information regarding the comparison of CDM resources to supply resources, please refer to Section 6.3 Comparing Supply-Side Resources.

4. Concepts & Components of Cost Effectiveness Tests

This section details the concepts (the overarching guidelines of CDM cost effectiveness) and components (the cost and benefit inputs required to complete CDM cost effectiveness) required to evaluate CDM cost effectiveness using the tests outlined above. Guidance for the treatment and calculation of benefits and costs are described to ensure consistency in assessing cost effectiveness, thus enhancing the comparability of results. Figure 4.1 | Concepts & Components and Table 4.1 | Components & Tests visually outline how the components, concepts and tests interact.

Figure 4.1 | Concepts & Components

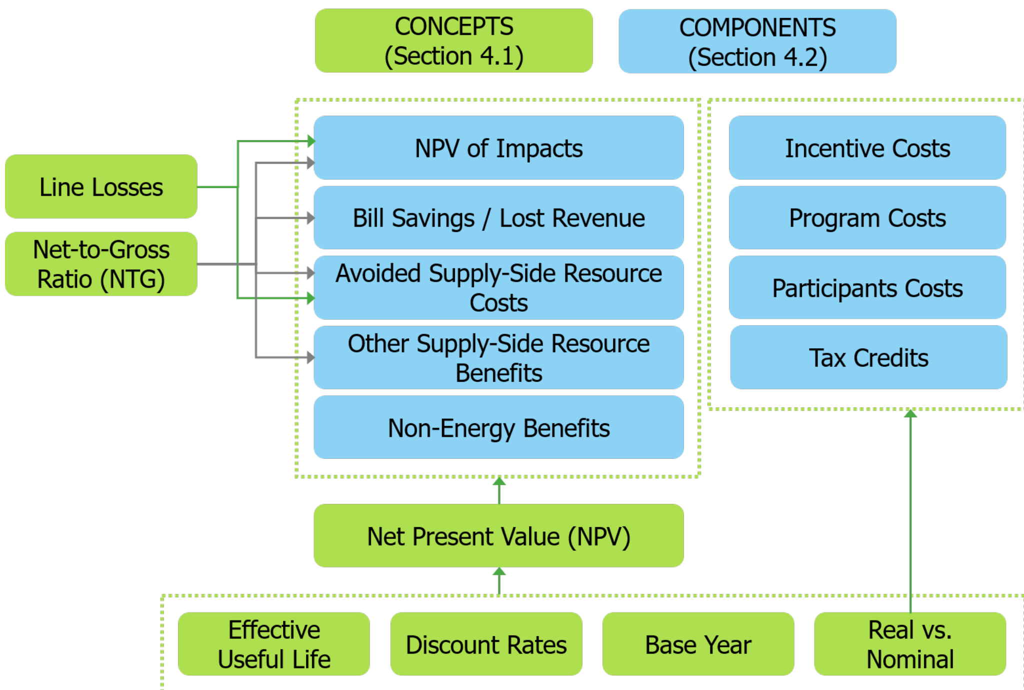


Table 4.1 | Components & Tests

Components	Total Resource Cost (TRC) Test	Societal Cost (SC) Test	Program Administrator Cost (PAC) Test	Ratepayer Impact Measure (RIM) Test	Participant Cost (PC) Test	Levelized Delivery Cost (LC) Metric
Avoided Electricity supply-side resource costs	*Benefit*	*Benefit*	*Benefit*	*Benefit*		
Other Supply-Side Resource Benefits	*Benefit*	*Benefit*		*Benefit*		
Bill Savings/Lost Revenue				*Cost*	*Benefit*	
Participant Costs	*Cost*	*Cost*			*Cost*	
Incentive Costs	*Benefit / Cost*	*Benefit / Cost*	*Cost*	*Cost*	*Benefit*	*Cost*
Program Costs	*Cost*	*Cost*	*Cost*	*Cost*		*Cost*
Non-Energy Benefits/Externalities	*Benefit*	*Benefit*				
NPV of Impacts						*Benefit*
Tax Credits	*Benefit*	*Benefit / Cost*			*Benefit*	

4.1 Concepts

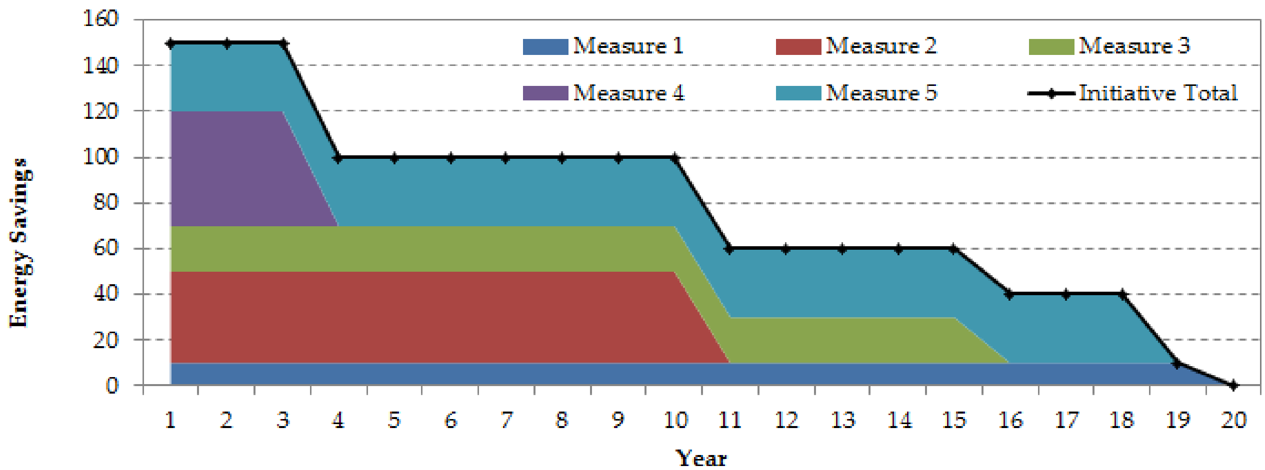
There are several overarching concepts integral to calculations of cost effectiveness. These concepts are used to calculate the components and may also apply to one or more cost effectiveness tests. Each of the concepts are used to calculate one or more of the cost effectiveness components. The components section will specify which concepts apply.

4.1.1 Effective Useful Life (EUL)

Description: Each measure or conservation action has a length of time over which it will provide peak demand and/or energy savings. For technology-based measures this is typically based on an estimate of the number of years that equipment will operate to a certain standard. For non-technology or behaviour-based CDM, EUL is more specific to each jurisdiction and depends on the type of program, maturity and details of the program design.

Use: When assessing cost effectiveness, the peak demand and/or energy savings that persist over the EUL of a measure determine the benefit (or cost) of that measure. Each measure in a given program may have a different EUL. Measure-level EULs are provided in the IESO's *Measures and Assumptions Lists*[6] and updated on a regular basis. When assessing cost effectiveness, the benefits must be calculated for each measure using its corresponding EUL and then aggregated to the program, and portfolio level. Measures in a program may have different EULs. Figure 4.3 | Illustrative Example of Program EUL illustrates this concept.

Figure 4.3 | Illustrative Example of Program EUL



When calculating the lifetime energy savings of a measure, it is important to understand the status of the existing or baseline measure. In some instances, a technology is replaced at the end of its EUL. This scenario is called "Replace on Burnout." In this case, the savings and costs used to calculate the cost effectiveness components are determined using the difference in the energy use of the efficient technology and the least-cost, code-compliant baseline technology over the EUL of a measure. In other scenarios, participants will replace a technology before the end of its EUL (i.e. while the existing equipment is still functional). This is called "Early Retirement" or "Early Replacement" In this scenario, the savings used to calculate the cost effectiveness components are a result of a two-step calculation:

1) The difference in energy use between the efficient and the existing technology for the remaining useful life (RUL) of the existing technology; and
2) The difference in energy use between the efficient and the code-compliant, baseline technology for the remainder of the EUL of the efficient technology (i.e. EUL-RUL).

When performing the cost effectiveness assessments for early retirement scenarios, it is most accurate to calculate the benefits and costs based on savings relative to the existing and code-compliant technologies.

6 Available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/conservation/Measures-and-Assumptions/IESO-Prescriptive-Measures-Assumptions-List-2020.pdf?la=en

For example, in year 1, a participant replaces an existing unit with an EUL of 6 years that consumes 10 kWh per year with a more efficient unit that consumes 5 kWh per year. The existing unit is expected to function for an additional three years (i.e. RUL = 3 years). The current code-compliant baseline equipment for this technology consumes 8 kWh per year. From year 1 to year 3 (RUL), the savings is equivalent to difference in consumption between the existing equipment and the new efficient technology (i.e. 10-5 = 5 kWh). From years 4 to 6 (EUL – RUL), the savings is equivalent to the difference in consumption between the code-compliant, baseline equipment and the new efficient technology (i.e. 8-5 = 3 kWh). Lifetime energy savings are the kilowatt hours that are saved over the entire effective useful life of a measure. Lifetime energy savings are the kilowatt hours that are saved over the entire effective useful life of a measure. In the example below, the measure has achieved 24 kWh of lifetime energy savings. Figure 4.4 | Illustrative Example of Early Retirement illustrates this example.

Figure 4.4 | Illustrative Example of Early Retirement

	← RUL →			← EUL - RUL →		
Existing	10 kWh	10 kWh	10 kWh			
Efficient	5 kWh	5 kWh	5 kWh	5 kWh	5 kWh	5 kWh
Baseline	8 kWh	8 kWh	8 kWh	8 kWh	8 kWh	8 kWh
Savings	5 kWh	5 kWh	5 kWh	3 kWh	3 kWh	3 kWh
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**

Early retirement also impacts the calculation of participant costs. Section 4.2.4 Participants Costsprovides additional detail on the determination of participant costs in an early retirement scenario.

4.1.2 Real (Inflation-Adjusted) vs. Nominal Dollars

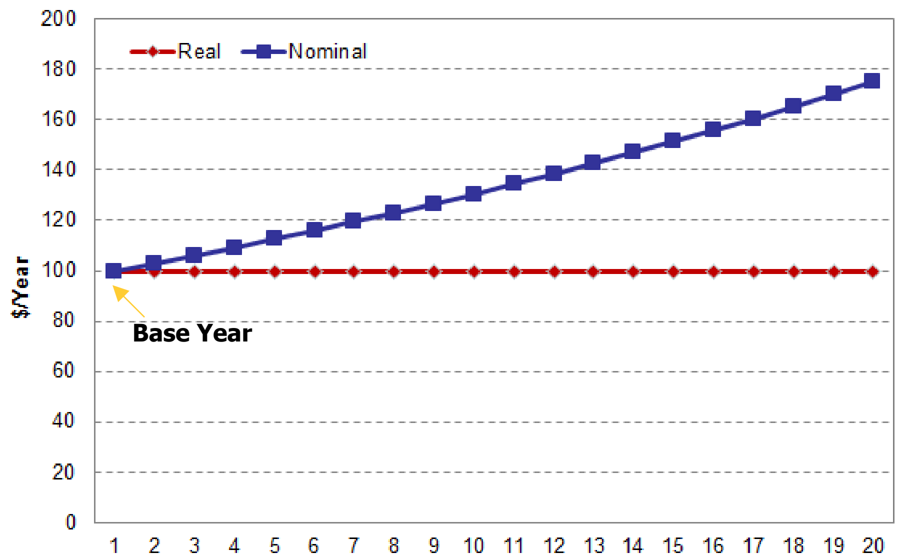
Description: Since the costs and benefits associated with the implementation of CDM are assessed over a span of time (i.e. the EUL of a measure) they must be adjusted for forecast inflation. Nominal dollars reflect the value of costs and benefits in the year as observed in the year in which they occur (the "sticker price"). Real or inflation-adjusted dollars reflect the value of costs and benefits in some given base year's dollars.[7] This allows comparison between like CDM costs (which are typically much higher in the initial years of a program) and benefits (which tend to be evenly distributed across the lifetime of a measure). Figure 4.5 | Real vs Nominal Dollars illustrates the divergence between real and nominal dollars.

Use: When assessing cost effectiveness, it is important to be consistent in the treatment of costs and benefits. Using real dollars to evaluate cost-effectiveness is a leading industry practice that should be

7 Typically, but not always, the chosen base year is the current year, so for example, benefits realized in future years (i.e. 2020, 2021 and 2022 would be expressed in current year (i.e. 2019) dollars. Base year will be discussed in more detail in Section 4.1.4 Base Year.

followed unless a very strong reason exists not to. The inflation rate used to adjust nominal values is provided in Appendix A.

Figure 4.5 | Real vs Nominal Dollars



Due to inflation, the value $180 in year 20 would only be $100 when expressed in base year dollars.

4.1.3 Discount Rates

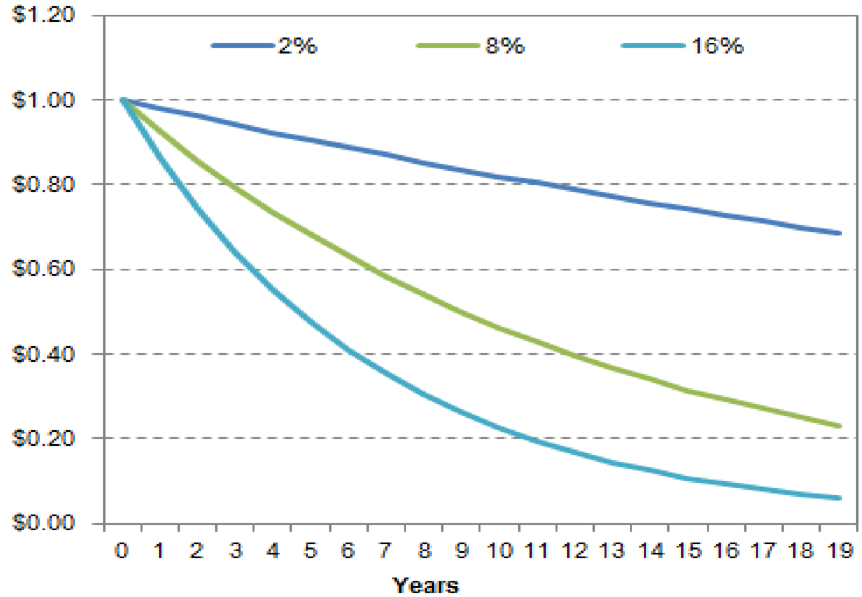
Description: The discount rate expresses the time value of money. The time value of money simply means that a dollar available immediately is worth more than a dollar provided a year from now. This difference in value exists because a dollar available immediately may be invested and deliver some returns immediately, whereas a dollar available in a year may not. The time value of money (and thus the discount rate used) is not constant for all individuals, organizations or sectors. For example, the time value of money for government will differ from a private company that must access capital and earn interest through financial markets.

Use: The discount rate can have a large effect on the results of a cost effectiveness analysis. Figure 4.6 | Impact of Varying Discount Rates illustrates the impact of various discount rates on the value of $1 over 20 years[8]. The higher the discount rate, the faster the dollar loses value as the delay in acquiring that dollar increases over time. Some jurisdictions will vary the discount rate according to the perspective being evaluated. The discount rates used to evaluate cost effectiveness are provided in Appendix A.

When performing a cost effectiveness assessment, the discount rate should be applied to real (inflation-adjusted) streams of benefits and costs.

8 Dollars are assumed to be real (inflation-adjusted).

Figure 4.6 | Impact of Varying Discount Rates



The higher the discount rate, the faster the dollar loses value.

4.1.4 Base Year

Description: The base year selected represents the year that is used as a basis for valuing costs and benefits.

Use: When evaluating single year cost effectiveness, the base year of the analysis typically reflects the year in which CDM is implemented (i.e., the "program year"). In situations where the user may not have the cost inputs for the program year (i.e. during the program design phase), a base year that is not the "program year" may be used. When multiple program years of CDM are assessed, a consistent base year should be used to assess benefits and costs to ensure consistency across all program years included in the analysis. Please refer to Section 6.2 Screening Aggregation for more information regarding different screening aggregation.

4.1.5 Net Present Value

Description: The Net Present Value (NPV) incorporates the concepts in Sections 4.1.2 Real (Inflation-Adjusted) vs. Nominal Dollars, 4.1.3 Discount Ratesand 4.1.4 Base Yearto calculate the time value of money.

Use: The equation below outlines how to calculate the NPV of costs or benefits, where C_t is the discrete cash flow (i.e., costs or benefits) in real dollars for time period t (i.e., year the costs or benefits occur minus the base year), T is the total number of time periods (i.e., years in the EUL), and d is the discount rate.

$$NPV = \sum_{t=0}^{T} \frac{Ct}{(1+d)^t}$$

4.1.6 Net-to-Gross Ratio (NTGR)

Description: The net-to-gross ratio (NTGR) is an adjustment factor that determines the benefits and costs that are attributable to CDM.

The NTGR may reflect one or more of the following elements (where applicable):

- Free Ridership (FR): Percentage of participants that would have implemented the CDM measure or conservation action even without the CDM program;
- Spillover (SO): Actions taken by consumers to implement CDM measures without an incentive because they are influenced by the CDM program. Note that both participant and non-participant spillover exists; and,
- Rebound Effect (RE): Influence of a CDM program on the market behaviour and baselines through increased adoption of energy efficient measures, practices, or services by the broader market.

Elements of gross savings[9] are not included in this Guide. For full details on the components of both gross and net savings, please refer to the IESO's *EM&V Protocols V4.0*.[10]

Use: The NTGR can be applied at the measure-level or at the program-level. In some cases, an element of the NTGR may not be applicable, and thus a value of zero should be used. For instance, rebound effects do not apply to newly launched programs that have not matured enough to have a lasting impact on the market baseline. In addition, the NTGR is dependent on program design, so it may not be appropriate to use the same NTGR for identical measures in different programs. For example, the NTGR for a measure in an instant rebate program would be different than the NTGR for a measure in a direct install program.

The equations below outline how to combine the elements above into a NTGR and how to use the NTGR to determine net savings from gross savings. The individual elements of the NTGR are always expressed as a percentage and thus will fall between 0 and 1. However, the NTGR itself may be greater than 1 in some instances.

$$Net\ to\ Gross\ Ratio = 1 - FR + SO + RE$$

$$Net\ Savings = Gross\ Savings \times Net\ to\ Gross\ Ratio$$

Net savings are not always used when assessing the costs and benefits of CDM. Each component is outlined in Section 4.2 Componentsand each test is outlined in detail in Section 5. Calculation of Cost Effectiveness Tests and will specify whether it is appropriate to use net or gross savings (i.e., whether or not an NTGR is used).

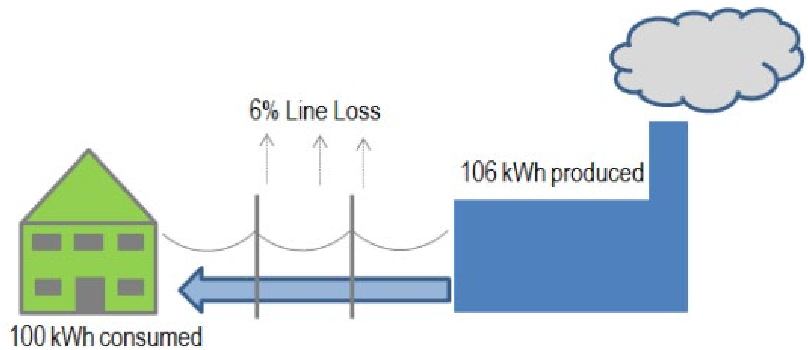
9 Realization Rate (comparing evaluated savings to estimated/reported savings; and usually includes the evaluation of in service rates, and changes in baseline assumptions), Interactive Effects (energy effects created by energy conservation measure but not measured within the measurement boundary), and Snap-back (an increase in energy using behaviour following customer action to increase efficiency) should be considered as part of the gross savings

10 Available at: Available at: https://www.ieso.ca/en/Sector-Participants/Energy-Efficiency/Evaluation-Measurement-and-Verification

4.1.7 Line Losses

Description: Line losses occur between energy produced at the generator and energy consumed by the customer or end-user, as illustrated in Figure 4.7 | Line Losses. As a result, energy savings observed by the end-user (the customer) are lower than savings observed by the generator.

Figure 4.7 | Line Losses



Use: Avoided costs, the direct electricity system benefits of CDM, are generally defined at the point of purchase (i.e., at the generator). To accurately capture the full benefits of CDM a line loss factor must be applied to peak demand and energy savings if they are determined at the customer/end-use site.

There are two components used to determine total line losses:

- Average losses on the distribution system (Dx losses); and,
- Average losses on the transmission system (Tx losses).

If a CDM participant is transmission-connected, only the Tx losses are accounted for. If a CDM participant is distribution-connected, both Dx and Tx losses are accounted for. Line losses are provided in Appendix A. Line losses are typically provided as a percentage that must be converted into a line loss factor (LLF). The LLF for both Tx and Dx losses is calculated using the equation below.

$$LLF = {}^{1}\!/_{(1 - (Tx\ Losses\ +\ Dx\ Losses))}$$

Once a LLF is calculated savings at the customer or end-user level can be converted to the generator level using the equation below.

$$Savings_{generator} = Savings_{Customer} \times LLF$$

Savings at the generator are used for valuing avoided electricity supply-side resource costs (i.e., system benefits), and savings at the customer or end-user level are used for lost revenue and bill savings calculations. Each component is outlined in Section 4.2 Componentsand each test is outlined in detail in Section 5. Calculation of Cost Effectiveness Tests and will specify whether it is appropriate to use savings at the generator level or the end-user/customer level (i.e., whether or not line losses are included).

4.2 Components

Each component outlined in the following section is used to calculate one or more cost effectiveness tests. Many of the components outlined below may use one or more of the concepts discussed previously.

4.2.1 Avoided Electricity Supply-Side Resource Costs

Concepts Required:

- ✓ 4.1.1 Effective Useful Life (EUL)
- ✓ 4.1.2 Real (Inflation-Adjusted) vs. Nominal Dollars
- ✓ 4.1.3 Discount Rates
- ✓ 4.1.4 Base Year
- ✓ 4.1.5 Net Present Value
- ✓ 4.1.6 Net-to-Gross Ratio (NTGR)
- ✓ 4.1.7 Line Losses

Description: Avoided electricity supply-side resource costs associated with the implementation of CDM consist of two main components:

- Avoided energy costs; and,
- Avoided capacity costs.

Avoided energy costs account for variable generation costs including the cost of fuel and variable O&M for power plants. Avoided capacity costs account for the reduction in coincident peak demand capacity including avoided generation capacity (i.e., capital and fixed O&M required to build new generation), transmission, and distribution capacity costs.

Use: The avoided supply-side resource costs are calculated using the annual energy savings and annual peak demand savings over the EUL of the measures associated with the implementation of CDM. Savings used in this calculation should account for the NTGR and line losses (i.e., net savings at the generator level) and should be converted to real dollars using a consistent base year.

Use the equation below to determine the total avoided supply-side resource costs.

$$\sum_{i=1}^{I}(\Delta EN_{it} \times MC{:}E_{it} \times K_{it}) + \sum_{i=1}^{I}(\Delta DN_{it} \times MC{:}D_{it} \times K_{it})$$

Where:

ΔEN_{it} = Net energy savings at the generator level in costing period i in year t (accounting for NTGR and including line losses)

ΔDN_{it} = Net peak demand savings in costing period i in year t, (accounting for NTGR and including line losses)

$MC{:}E_{it}$ = Marginal cost of energy in costing period i in year t

$MC{:}D_{it}$ = Marginal cost of demand in costing period i in year t

K_{it} = 1 when ΔEN_{it} or ΔDN_{it} is positive (a reduction) in costing period i in year t, and zero otherwise (i.e., a switch to count only positive costs)

Calculate the inputs to the equation above using the following steps.

Step 1: Calculate the net annual peak demand and energy savings at the generator level

Net peak demand savings (ΔDN) and energy savings (ΔEN) at the generator level are determined by applying the NTGR and the line loss factor (LLF) to gross energy savings at the end-user. Please refer to Sections 4.1.6 Net-to-Gross Ratio (NTGR) and 4.1.7 Line Lossesto review these concepts.

Step 2: Allocate lifetime net annual energy savings at the generator into costing periods

Load profiles provide a percentage breakdown of annual energy savings into three season and eight time-of-use buckets, or costing periods, specified in Figure 4.8 | Season and Time-of-Use Periods. The definition of each costing period can be found in Appendix A.

Figure 4.8 | Season and Time-of-Use Periods

Winter			Summer			Shoulder	
On-peak	Off-peak	Mid-peak	On-peak	Off-peak	Mid-peak	Off-peak	Mid-peak

Using the load profiles and the EUL assumptions for each measure in a CDM program, or portfolio, allocate each year (t) of net annual energy savings (ΔEN) at the generator level into costing periods, i (i.e., into eight season and time-of-use buckets). Figure 4.9 | Illustrative Example of Savings by Costing Period provides a simple illustrative example of how to break down annual savings into costing periods.

Figure 4.9 | Illustrative Example of Savings by Costing Period

Net Annual Energy Savings = 10 MWh, EUL = 1

	Winter			Summer			Shoulder	
t=1	On-peak	Off-peak	Mid-peak	On-peak	Off-peak	Mid-peak	Off-peak	Mid-peak
Load Shape	10%	10%	10%	10%	10%	10%	20%	20%
Calculation of Savings by Bucket	10% x 10 MWh	10% x 10 MWh	10% x 10 MWh	10% x 10 MWh	10% x 10 MWh	10% x 10 MWh	20% x 10 MWh	20% x 10 MWh
Savings by Bucket	1 MWh	1 MWh	1 MWh	1 MWh	1 MWh	1 MWh	2 MWh	2 MWh

Step 3: Multiply the savings by the corresponding marginal cost

To determine the avoided energy cost, multiply the net annual savings (ΔEN_{it}) by the corresponding marginal cost of energy for each costing period for the lifetime of the CDM measure, program, or portfolio $(MC: E_{it})$. The marginal cost of energy for each costing period and year can be found in Appendix A. If the marginal costs are not in real dollars using a consistent dollar year, they must be converted to align with all other costs and benefits.

Step 4: Determine the Avoided Capacity Costs

To determine the avoided capacity cost, multiply the net annual peak demand savings (ΔDN_{it}) by the corresponding marginal cost of demand over the EUL of the CDM measure, program, or portfolio $(MC: D_{it})$. The marginal cost of demand for generation, transmission and distribution by year can be found in Appendix A. If the marginal costs are not in real dollars using a consistent dollar year, they must be converted to align with all other costs and benefits.

Step 5: Adjust to Reflect NPV

Avoided supply cost assumptions should be discounted to reflect the NPV of lifetime resource savings benefits (i.e., benefits that persist over the EUL of measures) associated with the implementation of CDM. Please refer to Section 4.1.5 Net Present Valueto review this concept.

4.2.2 Other Supply-side Resource Benefits

Concepts Required:

- ✓ 4.1.1 Effective Useful Life (EUL)
- ✓ 4.1.2 Real (Inflation-Adjusted) vs. Nominal Dollars
- ✓ 4.1.3 Discount Rates
- ✓ 4.1.4 Base Year
- ✓ 4.1.5 Net Present Value
- ✓ 4.1.6 Net-to-Gross Ratio (NTGR)

Description: Other resource benefits resulting from the implementation of CDM may be present in addition to benefits associated with peak demand and energy savings affecting the electricity system. For example, installing insulation could reduce electricity use associated with an air conditioner in the cooling season and also reduce the natural gas use associated with a furnace in the heating season. Avoided supply-side resource costs associated with natural gas, fuel oil, or propane should be included where applicable in the determination of avoided supply-side resource costs for the TRC, RIM, and SC tests only[11].

In some cases, the implementation of CDM may result in the reduction of one supply resource, but an increase in another (i.e., fuel-switching). For example, a gas-powered clothes dryer replaces an electric

11 The IESO, as the program administrator, would use avoided electricity supply-side resource costs. If a utility is responsible for electricity and natural gas resources, both of these benefits and costs would be included.

clothes dryer, resulting in a reduction in electricity use, but an increase in natural gas use. Both the reduction in avoided electric supply costs and the increase in natural gas supply costs must be accounted for.

Use: To determine the avoided energy costs for CDM that reduces natural gas, propane, and/or fuel oil consumption, the net annual energy savings for each resource should be multiplied by the corresponding annual avoided cost assumption over the EUL of the CDM measure, program, or portfolio. For example, total natural gas savings (m^3) should be multiplied by the appropriate $/$m^3$ value to determine annual avoided natural gas costs. The avoided cost of other resources by year can be found in Appendix A. If the avoided costs are not in real dollars using a consistent dollar year, they must be converted to align with all other costs and benefits.

4.2.3 Bill Savings/Lost Revenue

Concepts Required:

- ✓ 4.1.1 Effective Useful Life (EUL)
- ✓ 4.1.2 Real (Inflation-Adjusted) vs. Nominal Dollars
- ✓ 4.1.3 Discount Rates
- ✓ 4.1.4 Base Year
- ✓ 4.1.5 Net Present Value
- ✓ 4.1.6 Net-to-Gross Ratio (NTGR)

Description: While reductions in energy and peak demand may lead to bill savings for utility customers, this also results in lost revenue for the utility. Therefore, this can be viewed as a benefit for the customer and as a cost for the utility.

Use: To determine participating customer bill savings associated with CDM, gross annual energy and peak demand savings at the customer or end-user level should be multiplied by annual electricity ratepayer cost assumptions over the EUL of the CDM measure, program, or portfolio. To determine participating utility lost revenue associated with CDM, net annual energy and peak demand savings at the customer or end-user level should be multiplied by annual electricity ratepayer cost assumptions over the EUL of the CDM measure, program, or portfolio. If natural gas, water, propane and fuel oil savings are present, these savings should be included by multiplying the annual savings by the corresponding annual ratepayer assumption. For example, the total natural gas savings in m^3 should be multiplied by the appropriate $/$m^3$ rate assumption to determine annual natural gas bill savings. Ratepayer assumptions for fuel oil, and propane should be based on their respective avoided costs. Ratepayer cost assumptions for both electricity and other resources can be found in Appendix A. If the cost assumptions are not in real dollars using a consistent dollar year, they must be converted to align with all other costs and benefits.

4.2.4 Participants Costs

Concepts Required:

- ✓ 4.1.1 Effective Useful Life (EUL)

- ✓ 4.1.2 Real (Inflation-Adjusted) vs. Nominal Dollars
- ✓ 4.1.3 Discount Rates
- ✓ 4.1.4 Base Year
- ✓ 4.1.5 Net Present Value

Description: Participant costs are the incremental capital and O&M costs, incurred by a participating customer to implement CDM. Participant costs are often categorized by the definition of the appropriate baseline which then determines how the costs are derived. The two categories are a) incremental or b) full installed as defined below.

a) **Incremental Cost:** is considered the difference in capital and/or material costs between the baseline and efficient (CDM) equipment. The baseline could be standard equipment, equipment or processes available during the time of replacement or in place prior to installation of an efficient measure. Installation and removal costs are often assumed to be equal for the baseline and efficient case and therefore are not considered a cost to the participant. The incremental cost basis is typically applied to the following scenarios:
   - Replace-on-Burnout (ROB): in the case of an energy efficient appliance being purchased instead of a standard model, the participant cost would be equal to the cost differential between the two options.
   - New Construction (NC): in the case of a new building or system being constructed or installed, the participant cost would be equal to the difference between an energy efficient option and the defined baseline or the market baseline.[12]

b) **Full Installed Cost:** is considered the cost of the efficient equipment including labour and removal costs (if applicable) of the existing equipment. The full installed cost basis is typically applied to the following scenarios:
   - Retrofit (RET) scenarios: in the case of residential attic insulation in a previously uninsulated attic, the full cost of the insulation, including installation, would be accounted for as the participant cost.
   - Early Retirement (ER) scenarios: is similar to the ROB scenario, but the equipment is replaced before the existing technology has reached the end of its useful life. The incremental cost is assumed equivalent to the full installed cost under this scenario. The participant cost is often discounted by a "deferred replacement credit" . . For a retrofit measure, deferred replacement credit is a credit for deferring the replacement cycle of

[12] Market baseline is the baseline corresponding to an efficiency level based on the common practice for new equipment or installations in the market.

the existing equipment due to early replacement [13]. To calculate the deferred replacement credit, it is assumed that the efficient measure will only be installed at the time of retrofit and that all subsequent replacements will be at the baseline efficiency. In addition, it is also assumed that the real cost of the baseline equipment will not change over time.

Use: Participant costs should include all incremental costs that are directly related to the implementation of CDM, including costs associated with installation, de-installation, shipping and decommissioning. Participant costs may be incurred throughout the lifetime of a CDM measure. For example, O&M costs may be incurred on a regular basis over a CDM measure's EUL.[14] Please refer to Section 4.1.1 Effective Useful Life (EUL) to review the concept of EUL. In this case, costs must be discounted and inflation-adjusted. Participant costs should not be adjusted for the impact of incentives provided to a participating customer by a program administrator since the incentive costs are considered another component of a cost effectiveness analysis and treated differently for different metrics. Participant costs should be included in a cost effectiveness analysis at the measure level.

Special cases and examples of interpreting whether a cost is considered an incentive cost, program cost, or participant cost can be found in Section 7. Special Cases/Examples

4.2.5 Incentive Costs

Description: Incentive Costs are costs that include cash incentives, payments for demand response services, upstream incentives, payments for studies, and in-kind contributions that the program administrator provides to participating customers, contractors, and trade allies to encourage the implementation of CDM by offsetting the incremental cost of efficiency (i.e., the participant costs).

Use: Any compensation resulting in a decrease in incremental cost to the program participant should be accounted for as an incentive cost even if payment is not received directly by the participant. For example, an appliance retirement program offers participants free pick-up of their old fridge or freezer. The cost to pick-up the appliance is estimated to be $100. Since the customer is directly receiving the benefit, the $100 is considered an incentive cost. In most cases, incentive costs should be included in a cost effectiveness analysis at the measure level as incentives are typically associated with the implementation of a particular technology.

Special cases and examples of interpreting whether a cost is considered an incentive cost, program cost, or participant cost can be found in Section 7. Special Cases/Examples

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13 For information on calculating a deferred replacement credit, please refer to the following memo. Rachel Brailove, John Plunkett, and Jonathan Wallach. "Retrofit Economics 201: Correcting Commons Errors in Demand-Side Management Cost-Benefit Analysis." Resource Insight, Inc. Circa 1990.

14 Note that only incremental O&M costs should be counted. For example, if a participant installs a high-efficiency furnace that requires $100 worth of maintenance each year, but a standard furnace also requires $100 worth of maintenance each year, then incremental O&M costs are zero.

4.2.6 Program Costs

Description: Program Costs are the costs related to the program design, implementation, marketing, evaluation and administration of CDM, inclusive of fixed overhead costs. Incentive costs are not a component of program costs since they are considered another component of a cost effectiveness analysis and treated differently for different tests.

Use: Program costs are often incurred at the program or portfolio level. Program costs can be incurred at the measure level as some program costs vary based on the number of measures implemented, otherwise known as variable costs (e.g., call centre labour for a program in which the installation of a measure requires participants call in and register). Program costs should be included in a cost effectiveness analysis at the level in which they are incurred. Costs incurred by a program administrator must be accounted for as either an incentive or program cost.

Special cases and examples on interpreting whether a cost is considered an incentive cost, program cost, or participant cost can be found in Section 7. Special Cases/Examples

4.2.7 Non-Energy Benefits (NEBs)/Externalities

Concepts Required:

- ✓ 4.1.1 Effective Useful Life (EUL)
- ✓ 4.1.2 Real (Inflation-Adjusted) vs. Nominal Dollars
- ✓ 4.1.3 Discount Rates
- ✓ 4.1.4 Base Year
- ✓ 4.1.5 Net Present Value

Description: NEBs represent improvements in the quality of life for program participants and/or society as a whole and are not typically captured by traditional cost effectiveness tests. Examples of NEBs include increased comfort, environmental improvements (i.e., reductions in greenhouse gas emissions, better air/water quality), reduction in health costs/improved health, water savings, and public/national security. NEBs and/or externalities vary depending on the perspective; some examples are noted in Table 4.2 | Perspectives of Externalities.

Table 4.2 | Perspectives of Externalities

Customer Perspective	Utility Perspective	Societal Perspective
• Increased comfort • Improved air quality • Greater convenience	• Reduce the number of shutoff notices issued • Reduce bill complaints received	• Regional benefits in increased community health and improved aesthetics • Reduces reliance on imported energy sources, providing provincial security benefits

Use: Some NEBs are easier to quantify than others. When feasible, NEBs should be translated into a dollar value. However, in order to avoid the complex challenges associated with quantifying the benefits associated with non-energy benefits, a number of jurisdictions have implemented a fixed adder or adjusted discount rate to determine the cost effectiveness of CDM programs.

The IESO is utilizing a 15 percent adder and as a net benefit calculated for the Total Resource Cost Test to take into consideration of non-energy benefits with CDM programs. The 15 per cent adder is supported through studies of other jurisdictions as well as IESO's independent study findings. The IESO will continue to explore further research to quantify NEBs and will update this figure if deemed appropriate.

4.2.8 Tax Credits

Description: Tax credits capture any tax benefits at the municipal, provincial or federal level for which participants are eligible and may claim as a result of participating in CDM.

Use: Tax credits that can be attributed to the implementation of CDM may be included in the benefits, where appropriate. Tax credits can be used to calculate a PC and TRC ratio, but not for an SC ratio as they represent a transfer. The NTGR should be accounted for when assessing cost effectiveness from a TRC perspective.

4.2.9 Net Present Value (NPV)

Concepts Required:

- ✓ 4.1.1 Effective Useful Life (EUL)
- ✓ 4.1.2 Real (Inflation-Adjusted) vs. Nominal Dollars
- ✓ 4.1.3 Discount Rates
- ✓ 4.1.4 Base Year
- ✓ 4.1.5 Net Present Value
- ✓ 4.1.6 Net-to-Gross Ratio (NTGR)
- ✓ 4.1.7 Line Losses

Description: CDM resources are typically procured with a one-time payment in a given year and deliver a stream of peak demand and/or energy savings in the future. Determining the net present value (NPV) of the impacts or peak demand and energy savings achieved over the EUL of the measures associated with the implementation of CDM allows the costs and the benefits to be directly compared.

Use: Using the equation and guidance in Section 4.1.5 Net Present Valueto determine the net present value of the net energy savings at the generator level, where C_t would represent the peak demand or energy savings.

5. Calculation of Cost Effectiveness Tests

The following section outlines how the components above are combined to evaluate cost effectiveness using the tests described in Section 3. Use of Cost Effectiveness TestsTable 5.1 | Overview of Costs and Benefits lists each component and indicates whether it is a benefit, cost, or transfer for each metric. Transfers have no net impact on the given test result.

Table 5.1 | Overview of Costs and Benefits

Component	TRC	SC	PAC	RIM	PC	LC
Avoided Electricity supply-side resource costs	*Benefit*	*Benefit*	*Benefit*	*Benefit*		
Other Supply-Side Resource Benefits	*Benefit*	*Benefit*		*Benefit*		
Bill Savings/Lost Revenue				*Cost*	*Benefit*	
Participant Costs	*Cost*	*Cost*			*Cost*	
Incentive Costs	*Transfer*	*Transfer*	*Cost*	*Cost*	*Benefit*	*Cost*
Program Costs	*Cost*	*Cost*	*Cost*	*Cost*		*Cost*
Non-Energy Benefits/Externalities	*Benefit*	*Benefit*				
NPV of Impacts						*Benefit*
Tax Credits	*Benefit*	*Transfer*			*Benefit*	

The result for each test may be expressed as a "net benefit" (Net B) in absolute dollars representing the difference between the present value (PV) of the inflation-adjusted benefits and the PV of the inflation-adjusted costs, or as a "benefit/cost ratio" (BC ratio) determined by dividing the PV of the inflation-adjusted benefits by the PV of the inflation-adjusted costs. The equations below demonstrate how the results of each test may be expressed.

$$Net\ B\ (\$) = PV(Benefits) - PV(Costs) \qquad BC\ Ratio = {}^{PV(Benefits)}\!/_{PV(Costs)}$$

This section will outline the calculation of the benefits and costs for each test and specify whether each component of that calculation is net (i.e., takes into account the NTGR) or gross (i.e., does not take into account the NTGR). A few key considerations to note:

- Steps should be taken to avoid double counting of benefits and/or costs when calculating cost effectiveness tests. For example, when savings from a behavioural program can also be attributed to an incentive program, the benefits should only be counted once.
- Costs associated with particular measure types must be treated consistently. It is *not* appropriate to treat costs differently to ensure the passing of a cost effectiveness test;
- Net peak demand and energy savings are used to calculate the components for all cost effectiveness tests with the exception of the PC test which is based on gross savings;
- Benefits should accrue for as long they persist over the EUL of CDM. O&M Costs should also be accounted for over the EUL of the measure(s);
- Incentives and program costs are always gross (i.e. include the costs associated with free-riders); and,
- Participant costs are always adjusted for NTGR in the TRC and SC tests but are not adjusted for NTGR in the PC test.

5.1 Total Resource Cost (TRC) Test

Benefits (B)	Costs (C)
• Avoided Supply-Side Resource Costs (net, generator level) • Other Supply-Side Resource Benefits (net) • Tax Credits (net) • Non-Energy Benefits/Externalities (net)	• Participant Costs (net) • Program Costs (gross)

The TRC benefits and costs are calculated using the following equations and components:

$$Benefits = ASC + ORB + TC + NEB$$

$$Costs = PTC + PRC$$

Where:

ASC = Avoided supply-side resource costs
ORB = Other supply-side resource benefits
TC = Tax credits
NEB = Non-energy benefits
PTC = Net participant costs
PRC = Program costs

Incentive costs are not included in the TRC test as they are a transfer from a program administrator to participating customers, and consequently do not impact the net benefit.

5.2 Societal Cost (SC) Test

Benefits (B)	Costs (C)
• Avoided Supply-Side Resource Costs (net, generator level) • Other Supply-Side Resource Benefits (net) • Non-Energy Benefits/Externalities (net)	• Participant Costs (net) • Program Cost (gross)

The SC test benefits and costs are calculated using the following equations and components:

$$Benefits = ASC + ORB + NEB$$
$$Costs = PTC + PRC$$

Where:

ASC = Avoided supply-side resource costs

ORB = Other supply-side resource benefits

NEB = Non-energy benefits

PTC = Participant costs

PRC = Program costs

The societal cost test may use an adjusted discount rate.

5.3 Program Administrator Cost (PAC) Test

Benefits (B)	Costs (C)
• Avoided Supply-Side Resource Costs (net, generator level)	• Incentive Costs (gross) • Program Cost (gross)

The PAC test benefits and costs are calculated using the following equations and components:

$$Benefits = ASC$$
$$Costs = IC + PRC$$

Where:

ASC = Avoided supply-side resource costs

IC = Incentive costs

PRC = Program costs

For the PAC test, avoided supply-side resource costs only include avoided costs associated with the electricity system[15].

5.4 Ratepayer Impact Measure (RIM) Test

Benefits (B)	Costs (C)
• Avoided Supply-Side Resource Costs (net, generator level)	• Incentive Costs (gross) • Program Cost (gross) • Lost Revenue (net, end-user/customer level)

15 The IESO, as the program administrator, would use avoided electricity supply-side resource costs. If a utility is responsible for electricity and natural gas resources, both of these benefits and costs would be included..

The RIM test benefits and costs are calculated using the following equations and components:

$$Benefits = ASC$$

$$Costs = IC + PRC + LR$$

Where:
ASC = Avoided supply-side resource costs
IC = Incentive costs
PRC = Program costs
LR = Lost revenue

5.5 Participant Cost (PC) Test

Benefits (B)	Costs (C)
• Bill Savings (gross, end-user/customer level) • Incentive Cost (gross) • Tax Credits (gross)	• Participant Costs (gross)

The PC test benefits and costs are calculated using the following equations and components:

$$Benefits = BS + IC + TC$$

$$Costs = PTC$$

Where:
BS = Bill savings
TC = Tax credits
IC = Incentive costs
PTC = Participant Costs

5.6 Levelized Delivery Cost (LC) Metric

Benefits (B)	Costs (C)
• NPV of impacts (peak demand or energy savings) (net, generator level)	• Incentive Costs (gross) • Program Costs (gross)

The LC metric is calculated differently than the other tests. The equation and components used to calculate the LC metric is specified below:

$$LC\ Metric = \frac{(IC + PRC)}{NI}$$

Where:
IC = Incentive costs
PRC = Program costs
NI = NPV of impacts (peak demand or energy savings)

6. Cost Effectiveness Guidelines

This section provides additional guidelines and other information required to evaluate and use cost effectiveness tests from various perspectives.

6.1 Assumptions

Cost effectiveness tests use many different assumptions that vary by jurisdiction. These assumptions include:

- Inflation Rate
- Discount Rates
- Base Year
- Line Losses
- Costing Period Definitions
- Avoided Supply Cost Tables
- Ratepayer Assumption Tables

Assumptions used to assess cost effectiveness in Ontario are specified in Appendix A and may be subject to change.

6.2 Screening Aggregation

Cost effectiveness tests can be performed at the measure, program, or portfolio level for a single year or multiple years and for energy efficiency and/or demand response. Performing cost effectiveness analyses at different levels of aggregation can be useful to determine the contribution of costs and benefits for the purposes of program design, re-design, and evaluation.

Different levels of aggregation will be appropriate for different situations. Table 6.1 | Screening Aggregation outlines a selection of screening aggregation examples with a description and some suggested uses.

Table 6.1 | Screening Aggregation

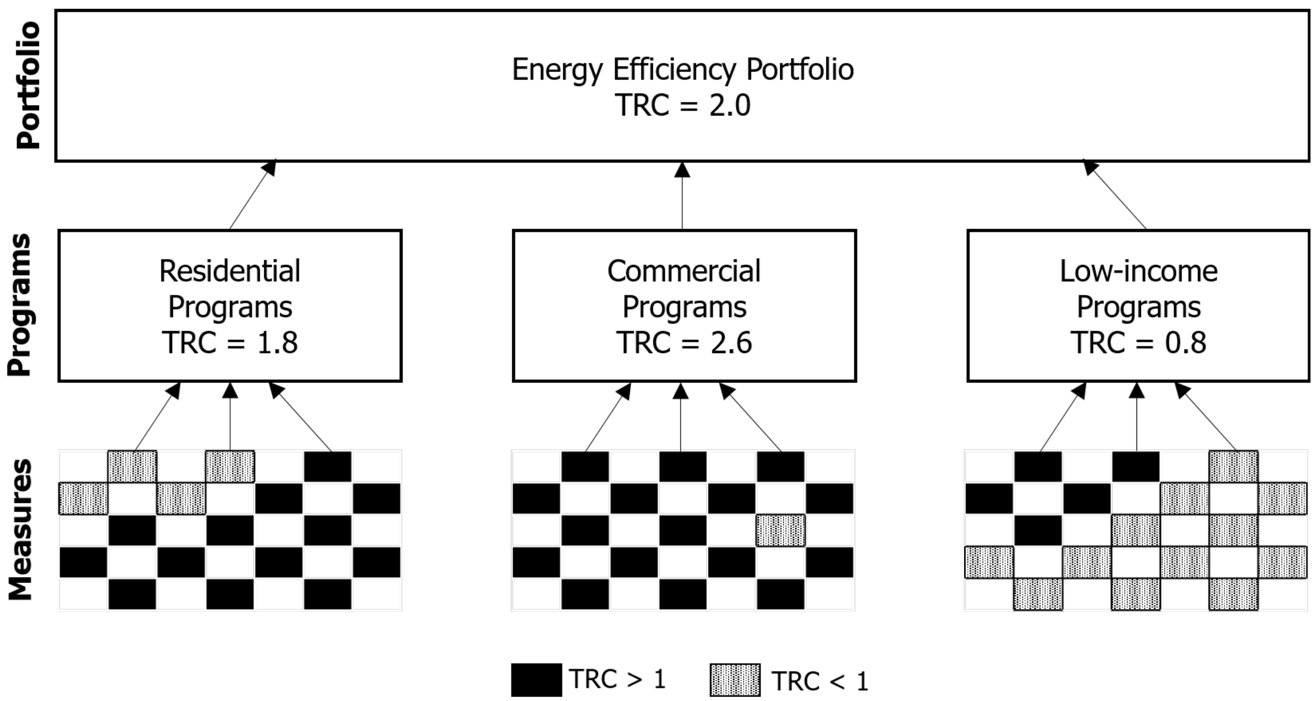
Measures	• Most benefits and costs can be easily defined or calculated at the measure level. • Most incentive costs are incurred at the measure level. • Measure level cost effectiveness can be useful for comparing measures to each other.

Programs	• When assessing cost effectiveness at the program level, the costs and benefits within the program are aggregated, with the exception of costs incurred at the portfolio level. • It is appropriate to include program administration costs at this level if not already applied at the measure level. o An example of a program cost incurred at the program level is the cost for program specific marketing. • Program level cost effectiveness can be useful for comparing program performance year over year and for assessing the performance of different segments. • Evaluation typically occurs at the program level aggregation.
Portfolios	• Cost effectiveness at the portfolio level should account for all costs and benefits associated with the design, delivery, and implementation of CDM. • This may include some overhead costs that were not previously allocated to a measure or program. o An example of program costs incurred at the portfolio level is overhead administration costs such as the payroll and office facilities of the program administrator. • Portfolio level cost effectiveness can be useful for assessing year over year performance of the CDM portfolio, for assessing the overall net benefit of CDM by a program administrator and monitoring the impacts of a change to the portfolio on overall net benefits.
Single Year	• Provides an instantaneous snapshot of cost-effectiveness. • Useful for comparing cost effectiveness of CDM from year to year but may understate benefits relative to costs, since benefits tend to accrue evenly across an EUL whereas costs are often mostly accrued in the first year of the EUL.
Multiple Years	• Provides a broader viewpoint and is useful for determining overall cost effectiveness for CDM which may have variable savings and costs year to year.

	• Some programs, and/or portfolios may have extensive up-front costs (e.g., administration, marketing, capability building) and as they mature, the fixed costs tend to diminish and are able to more cost effectively achieve greater savings. o In this instance, a single year snapshot assessment would understate cost effectiveness in the early stages of the program, or portfolio (e.g., appear less cost effective), and overstate cost effectiveness in the later stages. • A multi-year perspective typically provides a more holistic depiction of the long-term cost- effectiveness of the program. • This is also true for programs, and portfolios with long lead times.

As shown in Figure 6.1 | Illustrative Example of Portfolio TRC, not all measures or programs will produce a positive net benefit. However, when a program, or portfolio of programs as a whole is assessed, the benefit could be positive. For example, this allows some non-cost-effective measures or programs to be offered as long as the portfolio is cost effective.

Figure 6.1 | Illustrative Example of Portfolio TRC[16]



16 Adapted from: National Action Plan for Energy Efficiency (2008). Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers. Energy and Environmental Economics, Inc. and Regulatory Assistance Project. Available at: https://www.epa.gov/sites/production/files/2015-08/documents/cost-effectiveness.pdf

When calculating cost effectiveness for any level of aggregation, it is not appropriate to simply combine the outputs (i.e., the net benefits or cost benefit ratios). Instead, the inputs (i.e., the costs and benefits themselves) must be re-calculated with consistent assumptions and then aggregated. The steps below outline this process for a multi-year cost effectiveness analysis.

Step 1: Ensure Consistency across Assumptions

Align the assumptions used to calculate the NPV of the cost and benefit components (i.e., base year, real vs. nominal, inflation rate, and discount rate). Please refer to Section 4.1.5 Net Present Value to review this concept. It is not necessary to modify the EUL or NTGR assumptions used within each year of a multi-year analysis. The EUL and NTGR should align with the program year as these components can change year to year.

Step 2: Aggregate Components

Sum each cost and benefit component re-calculated with consistent assumptions across all levels of aggregation (e.g., all program years).

Step 3: Recalculate Metrics

Re-calculate the net benefit and costs; benefit and cost ratio, and LC metric with the aligned and summed benefit and cost components.

6.3 Comparing Supply-Side Resources

In general, cost effectiveness tests and the levelized cost metric provide a basis for not only comparing CDM measures, programs, or portfolios with each other, but also for comparing CDM to the cost of supply-side resources.

Each cost effectiveness test includes different costs (and benefits) and may not provide a full perspective when comparing to supply-side resources. It is important to understand all inputs of both CDM and supply-side metrics and the implications of comparing them directly. Some considerations include: whether a resource is base load or peaking, how long a resource is available, and the extent to which it can or cannot be dispatched.

With the exception of the PC test, all tests provide an estimate of the benefit of avoided supply-side resource costs. Typically, supply-side assessments include costs similar to a PAC test or LC metric (i.e., the costs incurred by a program administrator) and do not typically include costs incurred by participants, which are included in the TRC, SC, and PC.

6.4 Varying Avoided Costs

As mentioned in previous sections, avoided supply-side resource costs account for:

- Variable generation costs including the cost of fuel;
- Operating and maintenance costs for power plants; and
- Avoided generation, transmission and distribution infrastructure costs due to reduced peak demand.

Avoided supply-side resource costs translate energy savings and peak demand reductions into a dollar value. The assumptions used in the calculation of this dollar value may vary over time. If assumptions change, a challenge arises on how results of the tests can be compared. It is important to be aware of the underlying assumptions used to develop the avoided costs follow the policies and accepted assumptions specified in Appendix A of this Guide.

7. Special Cases/Examples

This section provides examples and special cases where the interpretation of the guidelines associated with cost components is not straight forward. In many cases, the details of the program design will provide guidance towards how costs should be treated and how changes in program design can impact the treatment of the costs. When interpreting costs, it is important to consider the implications on each test and to follow the principles below:

- Be consistent with the treatment of costs and benefits year over year, where appropriate, to ensure that results are comparable;
- Steps should be taken to avoid double counting of benefits and/or costs when calculating cost effectiveness tests, for example, when costs are considered program costs they cannot also be participant costs as that would result in the same costs being double counted in the TRC test; and,
- Costs incurred by a program administrator must be accounted for as either an incentive or program cost.

This is not intended to be an exhaustive list of all possible areas of ambiguity but provides some illustrative examples of how to interpret the definitions presented in this Guide.

7.1 Direct Install Measures

Case	The cost of replacing and/or installing energy efficient equipment is covered by a direct install program. The participant's costs are covered by the program administrator up to a certain cap.
Treatment	All equipment and installation costs should be treated as participant costs. All equipment and installation costs, up to the program cap (if applicable), should be treated as incentive costs.
Reasons	All incremental costs associated with equipment and installation should be accounted for as participant costs even if participant costs exceed a capped incentive level. The incentive transferred to a participating customer should be accounted for as incentive costs even if not received directly by the participant.
Example	If equipment and installation costs are $1,800 and the incentive level is capped at $1,500, these costs should be accounted for as $1,800 participant costs and $1,500 incentive costs. The $1,800 participant cost should be included in the TRC, SC, and PC. The $1,500 incentive cost should be included in the PAC, RIM, PC, and LC. Note that

	\$1,500 appears on both the benefit and cost side of the PC test delivering a net impact to the customer of \$300.

7.2 Midstream and Upstream Incentives

Case	Midstream incentives are costs incurred by a program administrator to provide assistance to retailers, distributors or dealers to promote CDM measures to their customers. Upstream incentives are incentives that a program administrator provides as assistance to manufacturers to promote CDM to downstream consumers.
Treatment	If all or part of the midstream and/or upstream incentive provided to manufacturers, retailers, distributors or dealers is directly passed on to consumers through a price discount then that amount should be accounted for as an incentive cost. If all or part of the midstream and/or upstream incentive provided to manufacturers, retailers, distributors or dealers is used in the promotion and marketing of CDM, then the midstream and/or upstream incentive should be treated as a program cost. If the allocation of the midstream and/or upstream incentive between price discount and marketing/promotion is unknown it should be accounted for according to policy direction.
Reasons	The discount passed on to consumers reducing the incremental cost to the participant should be accounted for as an incentive cost. If costs are used for marketing and promotion they should be accounted for as a program cost as the monetary benefit is not passed on to participants.
Example	A retailer is given \$25/unit to encourage participation in a CDM program. The retailer uses \$10/unit to promote CDM and \$15/unit is used to reduce the price of CDM measures. The retailer sells 100 units. The \$1,000 (\$10/unit x 100 units) used to promote the program should be included in the TRC and SC test as a program cost. The \$1,500 (\$10/unit x 100 units) passed to the customer should be included in the PC test as an incentive cost. The full \$2,500 (\$25/unit x 100 units) should be included in the LC, RIM, and PAC.

7.3 Performance Incentives

Case 1

Case	A third-party program administrator is delivering a particular CDM program and is provided with a performance incentive for achieving a certain amount of peak demand and energy savings.
Treatment	Costs associated with performance incentive payments should be treated as program costs. Performance incentives should be included in cost effectiveness assessments in the level in which they occur (i.e., measure, program, portfolio).
Reasons	Performance incentive payments are not directly transferred to customers and are not related to the incremental cost of implementing CDM, therefore they should be considered program costs. However, if the performance incentive is being used by the third party to increase the standard incentives provided to participants, then the performance incentives should be considered as incentive costs.
Example	A third-party program administrator is delivering a particular CDM program and is provided with a $100 performance incentive for achieving a certain amount of overall peak demand and energy savings. The program administrator does not pass this incentive on to participants. The $100 should be included in the TRC, SC, RIM, LC, and PAC as a program cost and should not be included in the PC test.

Case 2

Case	An Energy Performance Program provides participants annual incentives for achieving peak demand savings ($/kW) in addition to annual energy savings ($/kWh) for whole building energy savings in their facilities.
Treatment	Costs associated with performance incentive payments should be treated as incentive costs. Performance incentives should be included in cost effectiveness assessments in the level in which they occur, which is at program level in this case.
Reasons	Performance incentive payments are directly transferred to customers and are not related to the incremental cost of implementing CDM, therefore they should not be considered as incentive costs for TRC and SC.
Example	A participant avoided 100 kW in a given year and is provided $1/kW of peak demand savings. This results in a total of $100 performance incentive provided to the participant.

	The $100 should be included in the RIM, LC, and PAC as incentive costs and should be included in the PC test as a benefit.

7.4 Training

Case	A program administrator implements a capability building program to increase technicians' knowledge and/or expertise in the installation of air conditioners to support an efficient air conditioning program.
Treatment	Payments related to the training of technicians should be considered a program cost and should be accounted for at the level the training is impacting. In this case, the training directly impacts a program and thus can be included at the program level.
Reasons	The cost of the training is not offsetting the cost of implementing CDM for the participant, nor is the cost of training part of the incremental cost of the efficient technology (the cost of the CDM has not changed). Since costs incurred by a program administrator must be either an incentive or program cost, training is considered a program cost.
Example	A program administrator pays $2,000 for technicians to undergo training to more efficiently install air conditioners. As a result, air conditioners installed through the efficient air conditioning initiative save more per unit. The $2,000 should be included as program costs in the TRC, PAC, SC, RIM, and LC and should be assessed as part of the costs for the air conditioning program. The $2,000 should not appear in the PC test as this cost is not transferred to the participant.

7.5 Engineering Studies

Case	Funding for engineering studies is provided to participants to assist them in identifying energy efficiency opportunities (typically within a given cost cap).
Treatment	Any incentive payments made to account for the cost of the engineering study up to the cap should be considered an incentive cost. Payments related to engineering studies not included in the incentive cost should be considered a participant cost.
Reasons	In absence of the program, the customer would have to pay for the study. The program administrator is paying up to a certain cap for the cost of the study and is thus partially offsetting the cost to the participant.

Example	The Energy Performance Program provides customers a modelling incentive of $1,500 for each enrolled facility, which represents 80% of the total modeling study. The $1,500 should be included as participant costs and benefit in the TRC and SC. The net cost to the participant is $375. $1,500 should be included in the PAC, LC, and RIM test as an incentive cost. The $1,875 should appear in the PC test on the cost side as a participant cost and $1,500 incentive should appear on the benefit side delivering a net impact from the participant's perspective of $375.

7.6 Energy Manager Program

Case	A participant is provided an upfront payment to hire an energy manager, who is required to meet certain pay-for-performance criteria. This includes achieving a minimum energy savings per year. Energy managers can reach their targets through projects supported by other incentives, but a minimum of 10 per cent of energy savings must come from projects that have not received any incentive.
Treatment	Payments related to the hiring of an energy manager should be considered a program cost and should be accounted for at the level the energy manager is impacting. In this case, the energy manager directly impacts a program and thus can be included at the program level.
Reasons	The cost of hiring an energy manager is not offsetting the cost of implementing CDM for the participant, nor is the cost of hiring an energy manager part of the incremental cost of the efficient technology (the cost of the CDM has not changed). Since costs incurred by a program administrator must be either an incentive or program cost, hiring an energy manager is considered a program cost.
Example	A program administrator pays a participant $40,000 annually upon the hiring of an energy manager. As a result, the participant was able to implement an energy management plan. If the Energy Manager Program only accounts for 10% non-incented savings and 90% of savings are through other incented programs, the program cost for the Energy Manager Program should only be 10% of $40,000. In theory, the remaining 90% of the Energy Manager's salary should be attributed proportionally to the other incented programs. However, implementation of this may depend upon policy decisions and availability of data. $4,000 should be included as program costs in the TRC, PAC, SC, RIM, and LC and should be assessed as part of the costs for the Energy Manager program.

	The $4,000 should not appear in the PC test as this cost is not transferred to the participant.

Appendix A

Inflaction Rate: to convert real dollars to nominal dollars.

Inflation Rate	2.00 %

Discount Rate (Real): to calculate the NPV of costs and benefits.

Discount Rate	4.00 %

Base Year: to calculate the NPV of costs and benefits.

Base year	2020[17]

Line Losses: to calculate savings at the generator level.

Line Losses	**Percentage**
Average Distribution System Losses	4.20 %
Average Transmission System Losses	2.50 %

NEB Adder: to calculate TRC and SC NPV benefits

NEB Adder	15.00 %

[17] See section 4.1.4 – Base Year

Seasonal and Time of Use (TOU) Periods Definitions

Table 1 | Seasonal Periods

Season	Months Included
Winter	December – March
Summer	June – September
Shoulder	April, May, October & November

Table 2| Time of Use (TOU) Periods

TOU Period	Winter	Summer	Shoulder
On-Peak	0700 – 1100 and 1700 – 2000 weekdays (602 Hours)	1100 – 1700 weekdays (522 hours)	None
Mid-Peak	1100 – 1700 and 2000 – 2200 weekdays (688 hours)	0700 – 1100 and 1700 – 2200 weekdays (783 hours)	0700 – 2200 weekdays (1,305 hours)
Off-Peak	0000 – 0700 and 2200 – 2400 weekdays; All hours weekends and holidays (1,614 hours)	0000 – 0700 and 2200 – 2400 weekdays; All hours weekends and holidays (1,623 hours)	0000 – 0700 and 2200 – 2400 weekdays; All hours weekends and holidays (1,623 hours)

Note: Numbers are the daily hours for the various periods

Avoided Supply Costs

The following avoided supply costs are an output based on IESO Planning assumptions part of the Annual Planning Outlook for 2020[18]. These numbers are routinely updated by IESO Planning.

Table 3| Avoided Supply Costs ($ 2020)

Year	Winter On-Peak Avoided Cost of Energy ($/MWh)	Winter Mid-Peak Avoided Cost of Energy ($/MWh)	Winter Off-Peak Avoided Cost of Energy ($/MWh)	Summer On-Peak Avoided Cost of Energy ($/MWh)	Summer Mid- Peak Avoided Cost of Energy ($/MWh)	Summer Off-Peak Avoided Cost of Energy ($/MWh)	Shoulder Mid- Peak Avoided Cost of Energy ($/MWh)	Shoulder Off-Peak Avoided Cost of Energy ($/MWh)	Avoided Generation Capacity Costs ($/kW-yr)	Avoided Transmission Capacity Costs ($/kW-yr)	Avoided Distribution Capacity Costs ($/kW-yr)
2020	$16.73	$21.33	$16.87	$23.94	$27.44	$20.97	$19.17	$16.60	$0.00	-	-
2021	$17.06	$21.76	$17.20	$24.42	$27.99	$21.39	$19.55	$16.94	$0.00	-	-
2022	$23.32	$25.01	$26.97	$29.62	$28.83	$21.68	$24.45	$20.85	$0.00	-	-
2023	$31.85	$30.79	$28.71	$34.08	$33.29	$27.02	$27.24	$25.25	$62.06	-	-
2024	$33.49	$30.65	$32.74	$30.78	$31.97	$23.31	$26.55	$24.12	$44.65	-	-
2025	$36.07	$33.90	$35.75	$37.19	$37.16	$32.16	$29.77	$26.81	$55.67	-	-
2026	$37.67	$34.06	$32.05	$34.39	$34.06	$29.40	$27.82	$26.20	$59.80	-	-
2027	$37.09	$33.31	$33.32	$34.43	$34.05	$27.58	$24.84	$21.37	$59.34	-	-
2028	$35.14	$33.14	$28.01	$36.45	$35.60	$29.19	$27.76	$26.16	$60.88	-	-
2029	$39.04	$34.81	$30.52	$34.43	$34.47	$24.25	$25.95	$24.53	$54.98	-	-
2030	$36.13	$32.26	$30.27	$37.48	$36.45	$31.03	$29.78	$26.45	$59.46	-	-
2031	$40.60	$36.85	$31.84	$36.60	$34.86	$30.57	$29.58	$24.47	$57.66	-	-
2032	$38.41	$35.07	$30.51	$37.53	$34.14	$29.98	$27.30	$24.01	$62.12	-	-
2033	$38.30	$35.03	$32.22	$34.95	$33.40	$30.29	$28.32	$22.24	$61.42	-	-
2034	$37.95	$33.79	$22.62	$36.38	$34.15	$27.41	$27.89	$25.36	$61.59	-	-
2035	$35.73	$33.15	$19.80	$37.18	$34.99	$30.22	$27.85	$23.63	$60.99	-	-
2036	$35.32	$33.23	$26.60	$36.50	$36.15	$30.54	$28.12	$22.06	$69.48	-	-
2037	$36.98	$35.41	$29.29	$39.03	$36.00	$30.04	$29.08	$20.39	$59.71	-	-
2038	$39.22	$36.09	$30.97	$40.33	$36.91	$30.02	$27.54	$24.18	$62.89	-	-
2039	$43.59	$40.86	$35.42	$43.53	$44.58	$30.09	$29.20	$21.45	$61.99	-	-
2040	$41.92	$39.41	$33.91	$45.14	$48.61	$29.98	$25.92	$18.11	$63.65	-	-

18 https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

Ratepayer Assumptions

Electricity rates are based on 2017 LTEP Electricity Price Forecast[19]. Natural gas, propane, and heating oil values are based on natural gas avoided gas costs; water values are from best available information from IESO Planning.

Table 4| Ratepayer Assumptions

	Electricity	Natural Gas	Water	Propane	Heating Oil
Year	**2020 $/kWh**	**2020 $/MMBtu**	**2020 $/L**	**2020 $/L**	**2020 $/L**
2020	$0.14	$0.153	$0.003406800	$0.30	$0.35
2021	$0.14	$0.153	$0.003406800	$0.30	$0.35
2022	$0.15	$0.153	$0.003406800	$0.29	$0.35
2023	$0.15	$0.153	$0.003406800	$0.29	$0.34
2024	$0.16	$0.153	$0.003406800	$0.29	$0.34
2025	$0.16	$0.153	$0.003406800	$0.29	$0.34
2026	$0.16	$0.153	$0.003406800	$0.29	$0.34
2027	$0.16	$0.153	$0.003406800	$0.30	$0.35
2028	$0.16	$0.153	$0.003406800	$0.30	$0.36
2029	$0.16	$0.153	$0.003406800	$0.31	$0.37
2030	$0.16	$0.153	$0.003406800	$0.32	$0.38
2031	$0.16	$0.154	$0.003406800	$0.33	$0.39
2032	$0.16	$0.154	$0.003406800	$0.33	$0.39
2033	$0.15	$0.154	$0.003406800	$0.34	$0.40
2034	$0.15	$0.154	$0.003406800	$0.34	$0.40
2035	$0.15	$0.154	$0.003406800	$0.34	$0.41
2036	$0.15	$0.154	$0.003406800	$0.35	$0.41
2037	$0.15	$0.154	$0.003406800	$0.35	$0.42
2038	$0.15	$0.154	$0.003406800	$0.36	$0.42
2039	$0.15	$0.155	$0.003406800	$0.36	$0.43
2040	$0.15	$0.155	$0.003406800	$0.37	$0.44

19 Electricity rate values are a combined price for residential, commercial and industrial and was converted to 2020 dollars. Page 27 – 30; To access the 2017 LTEP, copy and paste https://files.ontario.ca/books/ltep2017_0.pdf into a browser.

Revision History

1. Sep 22, 2014 – Label on Avoided Cost of Energy Production table corrected. Summer and winter labels swapped. Pg. 58.
2. October 27 -15 per cent adder for non-energy benefits inserted in section 4.2.7.
3. April 1, 2019 – updated formatting, removed non-relevant material, updated outdated references, updated avoided costs and other assumptions.
4. January 20, 2020 – Updated formatting for AODA compliance and used latest IESO template, removed table for jurisdictional reviews of NEBs, updated values and assumptions in Appendix A as per updated data in CE Tool v.8.

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