ONTARIO ENERGY BOARD

EB-2021-0118

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

AND IN THE MATTER OF a consultation regarding a framework for energy innovation

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Environmental Defence's Responses to OEB Discussion Questions Re: Framework for Energy Innovation Working Group Report

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Introduction and overview

Distributed energy resources ("DERs") present a major opportunity to lower energy bills. For instance, non-wires alternatives ("NWA") can lower costs where they are more cost-effective than a traditional infrastructure solution. The overall benefits to the electricity system are particularly significant now that Ontario requires considerable amounts of new generation capacity.

The IESO's DER Potential Study found that "DERs can contribute to 25%-80% of Ontario's additional capacity needs over the next decade."[1] This is the achievable potential, which takes into account existing market barriers and compensation mechanisms. The economic potential, which focuses on cost-effectiveness, is roughly three times as large.[2] The IESO specifically notes that increasing access to the value of avoided or deferred distribution infrastructure costs would increase the achievable potential and help to shrink the large gap between economic and achievable potential.[3] As a result, the IESO specifically recommends that a transmission and distribution compensation framework be developed, stating as follows: "DERs can cost-effectively help meet Transmission and Distribution needs and thus they should be compensated for this value stream to ensure the system can benefit from the services DERs can provide."[4]

Deploying DERs to lower energy bills will require important adjustments to remove barriers. As the OEB has noted, current electricity distributor rate-making mechanisms provide inherent disincentives to implement DERs even where they are in the best interest of customers. Utilities are also very wary to propose or implement DERs without knowing if the regulator will agree with its approach to valuing the costs and benefits of the DER solution. Environmental Defence strongly supports the OEB's efforts to address these issues through various processes, and provides the below comments on the six discussion questions posed by the OEB to stakeholders.

Environmental Defence's recommendations can be summarized as follows:

- **Priorities:** The OEB should take a two-stage approach to these issues, with the first stage being immediate guidance that will allow utilities to move forward, followed by a second stage where more complex and detailed guidance is provided.

- **Scope of impacts for a benefit-cost analysis ("BCA") framework:** The OEB should adopt the well-known and frequently-used total resource cost test (TRC) as a middle ground between the narrower and broader options that are available. This should be followed by an in-depth examination that considers adjustments to this test and provides more detailed guidance.

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[1] IESO, *DER Potential Study, Final Results Presentation*, June 22, 2022, p. 19 (link).
[2] *Ibid*., p. 27.
[3] *Ibid*., p. 27.
[4] *Ibid.*, p. 30.

- **Removing disincentives:** The OEB should adopt an easy-to-implement immediate mechanism to ensure that utilities are agnostic between traditional capital investments and O&M spending on NWAs. This should be followed by a consideration of options that might require fundamental changes to rate-making mechanisms.

- **Planning for DER adoption:** The OEB should ensure that distributors consider and implement cost-effective methods to mitigate electricity system constraints (e.g. short circuit, thermal, and voltage-related) that prevent customers from being able to implement DERs that could help them lower their energy bills.

Priorities

Discussion question one asks: "What is the relative priority of the issues and next steps identified by the FEIWG?"

Environmental Defence submits that the OEB should prioritize (1) removing disincentives to NWAs, (2) preparing a BCA framework, and (3) mitigating electricity system constraints that prevent DER adoption. These steps are necessary to facilitate the use of NWAs to lower energy system costs and benefit consumers. If disincentives remain, the use of cost-effective NWAs will be far below their potential. Without a benefit-cost framework, utilities will be reluctant to propose and adopt NWAs as they will be uncertain whether the OEB will agree with their analysis and approve the requested spending. In addition, a benefit-cost analysis framework is important in order to:

- Provide consistency across utilities;

- Ensure utilities adopt best practices with respect to benefit-cost analysis; and

- Provide certainty to utilities such that they can plan for NWAs.

These items can be actioned simultaneously. However, for each of these items, we recommend that the OEB take a two-stage approach to these issues, with the first stage being immediate guidance that will allow utilities to move forward, followed by a second stage where more complex and detailed guidance is considered and provided.

We believe immediate guidance is needed in part because major distributors such as Alectra and Toronto Hydro are in the process of preparing their five-year distribution system plans. If guidance does not come fast enough, those plans may fall far short with respect to DERs and result in major missed opportunities from now until the end of the decade.

Specific recommendations for prioritization within each topic area are discussed below.

Developing a BCA Framework

Discussion question two asks:

> 2. What is the appropriate scope of a BCA Framework? In other words, should a narrow or broad set of benefits and costs be considered with respect to deployment of DERs as alternatives to traditional solutions to meet electricity distribution system needs?

Environmental Defence recommends that the OEB initially start by adopting one of the traditional cost-effectiveness tests, rather than developing a new approach. This could be done very quickly and would let utilities know which costs and benefits should be considered. This would be a major step forward. The benefits to this approach include:

- **Speed:** The traditional cost-effectiveness tests are extremely well-known and well-documented. For instance, electric utilities have applied all of the traditional tests as part of the former CDM program, with a focus on the total resource cost test (TRC).[5] Similarly, the gas utilities have used the TRC test for many years to examine demand-side management. A traditional test can be adopted quickly as a starting point.

- **Certainty:** Initially adopting a traditional test will provide the greatest initial certainty to utilities and the industry in general because these tests are so well known. There is a wealth of documentation detailing how the traditional tests should be applied in different situations. This includes Ontario-specific documentation. For instance, as far back as 2005 the OEB prepared a guide for electricity distributors applying the TRC.[6]

- **Robustness:** The traditional tests are robust and can handle any situation as they have been used countless times over the past decades.

As a second step, the OEB could (a) consider whether to make any adjustments to the cost-effectiveness test (e.g. add or subject certain impacts) and (b) develop more detailed guidance. Tackling the issue in this manner would provide the timely guidance that the industry urgently needs while also setting out a pathway for more detailed work.

Select the total resource cost test (TRC)

For the first initial phase of this work, Environmental Defence recommends selecting the TRC as the basis for the OEB's BCA framework. This represents a middle ground in terms of the breadth of benefits and costs to be considered. To explain this, we provide some background on the traditional cost-effectiveness tests.

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[5] IESO, *Conservation & Demand Management Energy Efficiency Cost Effectiveness Guide*, April 1, 2019 (link) (see also the 2021 version: link).

[6] OEB, *Guide to Applying the Total Resource Cost Test*, July 6, 2005 (link).

The traditional cost-effectiveness tests have been used for over four decades. They are described in the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* ("NSPM"). The NSPM was developed as a joint effort by a large number of leading energy policy experts across North America and is used widely in North America by leading utilities.[7] The NSPM details best practices for developing a benefit-cost analysis framework that is economically rational. The traditional "tests" are called "tests" because they are meant to inform a decision on whether to adopt a certain solution. In particular, they are meant to determine whether that solution is cost-effective.

The three main traditional cost-effectiveness tests are the utility cost test ("UCT"), the total resource cost test ("TRC"), and societal cost test ("SCT"). Although the participant cost test ("PCT") and rate impact test ("RIM") are traditionally referred to as cost-effectiveness tests, the NSPM notes that "they should not be used to answer the key question of which DERs should be funded or otherwise supported by utilities on behalf of customers."[8]

The scope of benefits and costs included in those traditional tests are described in the following figure from the NSPM:

Table E-2. Impacts Included in the Traditional Cost-Effectiveness Tests

	UCT	TRC Test	SCT	PCT	RIM Test
Electric Utility System Impacts	✓	✓	✓	-	✓
Gas Utility System Impacts	✓	✓	✓	-	✓
Other Fuel Impacts	-	✓	✓	✓	-
Host Customer Impacts	-	✓	✓	✓	-
Societal Impacts	-	-	✓	-	-
Host Customer Bill Savings	-	-	-	✓	✓

[9]

[7] National Energy Screening Project, *National Standard Practice Manual For Benefit-Cost Analysis of Distributed Energy Resources*, August, 2020 (link). The report authors includes Synapse Energy Economics, Energy Futures Group, ICF, Pace Energy and Climate Center, Schiller Consulting, Smart Electric Power Alliance, and E4TheFuture. The authors were also supported by an advisory group including participants from Recurve, Lawrence Berkeley National Laboratory, United States Environmental Protection Agency, Exelon Utilities, ESource, Southeast Energy Efficiency Alliance, Rocky Mountain Institute, Lumina, MJ Bradley, National Association of Regulatory Utility Commissioners, Washington Utilities and Transportation Commission, National Association of Energy Service Companies, New Hampshire Consumer Advocate, Northeast Energy Efficiency Partnerships, United States Department of Energy, Midwest Energy Efficiency Alliance, California Efficiency Demand Management Council.

[8] *Ibid*., p. E-2 (The NSPM goes on to describe the appropriate uses of the PCT and RIM as follows: "Instead, the PCT should be used to assist with program design and estimating customer participation, and the RIM Test should be used (a) to determine whether rates are likely to increase or decrease, and (b) to determine whether to conduct a rate, bill, and participation analysis.").

[9] *Ibid*., p. E-2.

The main contenders are the UCT, TRC, and SCT. The TRC represents the middle ground in terms of the breadth of impacts to be consider. In addition, it is the test that has been most widely used by utilities in Ontario in the context of energy efficiency, which itself is a DER.

In phase two of BCA development, the OEB could consider adding or subtracting from the TRC test. This was done in the gas context where the TRC plus test is applied. The "plus" refers to an adder to account for environmental and non-energy impact. But we recommend a phased approach so that utilities can start working on NWAs with some certainty now.

Although we recommend the total resource cost test (TRC), we also believe it would be reasonable for the OEB to adopt the utility cost test (UCT), or societal cost test (SCT), or a combination of those tests. All of these tests include energy system impacts and therefore focus on the overall goal of lowering overall electricity costs.

Do not select the rate impact measure (RIM)

Environmental Defence strongly recommends against adopting a rate impact test (RIM) to determine whether to adopt NWAs. The RIM focuses solely on the impact on rates, without accounting for other important potential benefits accruing to the distributor's customers outside of distribution rates, such as reduced electricity supply costs.

Adopting the RIM or an adaption of it would be contrary to best practices as described in the NSPM. Again, the NSPM explicitly states that the rate impact measure (RIM) "should not be used to answer the key question of which DERs should be funded or otherwise supported by utilities on behalf of customers."[10] In addition, the NSMP outlines in detail the major limitations of relying on the RIM as a measure of cost effectiveness, which are excerpted in Appendix A for ease of reference.

Note that the BCA subgroup report refers to the RIM as a "distribution service test." That term is not used by other jurisdictions or in the BCA literature, and so we have used the commonly-accepted term, RIM, in these comments.

Selecting the RIM test to decide whether to pursue NWAs would mean:

- Selecting options that will result in higher energy bills for the distributor's customers by disregarding non-distribution-system benefits that would accrue to those customers (e.g. reduced distribution line losses or avoided energy costs);

[10] *Ibid*., p. E-2 (The NSPM goes on to describe the appropriate uses of the PCT and RIM as follows: "Instead, the PCT should be used to assist with program design and estimating customer participation, and the RIM Test should be used (a) to determine whether rates are likely to increase or decrease, and (b) to determine whether to conduct a rate, bill, and participation analysis.").

- Effectively ruling out energy efficiency as a non-wires alternative as it is generally only cost effective when considering energy savings to the distributor's participating customers, which are excluded from the RIM test;

- Effectively ruling out voltage regulation as a cost-effective DER as it is generally only cost-effective when considering energy savings to the distributor's customers (e.g. see EB-2020-0249); and

- Contradicting a "fundamental principle" and one of the five "steps" outlined in the NSPM.[11]

Again, Environmental Defence recommends the TRC as a starting point and believes the SCT or UCT are also reasonable approaches, but strongly opposes using the RIM.

Fair distribution of costs and benefits

Some concerns were expressed in FEIWG discussions as to whether the TRC test would result in an unfair distribution of impacts if a distributor's customers end up paying for benefits that accrue to the entire energy system and therefore to other distributors' customers. However, that need not be the case. Utilities can be directed to ensure that costs follow benefits wherever that is possible. This can be accomplished, for instance, through the use of third party DER providers that monetize system-wide benefits from other parties (e.g. the IESO) such that the distributor only pays for the distribution system benefits.

However, that is not always possible due to market and regulatory barriers. But even if the distribution of costs and benefits is not perfect, that should not rule out the solution that generates the lowest energy bills for customers overall. If there is a problem with the distribution of costs or benefits, that should be fixed through means that do not involve selecting sub-optimal solutions that unnecessarily increase total system costs. In addition, an unequal distribution of impacts between the customers of different distributors should, at least to some extent, even out as all distributors would be following the same OEB framework. If impacts do not even out, mechanisms can be developed to transfer costs to those ratepayers who benefit the most without having to fall back on sub-optimal solutions to meeting distribution system needs.

This approach is consistent with the NSPM. The NSPM notes that the question of cost-effectiveness should be analyzed separately from the question of whether the impacts are distributed fairly. Those are two different questions. Trying to develop a single test to answer two questions will mean that neither are answered properly. It is best to determine which option is the most cost-effective and separately consider how to allocate the costs of the most cost-effective option.

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[11] *Ibid*., p. A-4 (limitations of this test), 2-6 (principle 5: incremental analysis), & 3-6 (step 2: include all utility system impacts)

In addition, Environmental Defence recommends that the OEB explore mechanisms to shift distributor DER costs to ensure that they follow the benefits where that is not possible in Ontario's energy markets. The specific mechanisms to do that are beyond the scope of these comments. However, this would be the best approach to address concerns about distributional fairness.

Stage two: adjustments and detailed guidance

As noted above, at stage two, the OEB could (a) consider whether to make any adjustments to the cost-effectiveness test (e.g. add or subject certain impacts) and (b) develop more detailed guidance, such as:

- Methodologies for calculating each cost and benefit;
- Proxies and simplifying assumptions that can be used to conserve scarce planning resources, and
- Template tools and spreadsheets.

Developing and implementing utility incentives

Discussion questions 3, 4, and 5 ask:

> "How might the OEB remove disincentives for utilities to adopt DER solutions?"
>
> "Is providing incentives to distributors to facilitate adoption of DER solutions (i.e., non-wires alternatives) appropriate? Under what circumstances?"
>
> "If incentives are appropriate, how should the OEB select/develop the form of incentive that should be available? Are there options the Incentive Subgroup did not identify that should be considered?"

How to remove disincentives

As the OEB has noted, there are major disincentives for utilities to implement cost-effective NWAs. These must be eliminated to realize the full potential of NWAs to lower energy costs. Environmental Defence recommends that the OEB use a two stage approach for this issue as well. First, the OEB would adopt an easy-to-implement solution that does not require fundamental changes to the rate-making mechanisms. Once this is in place, the OEB could consider more wide-scale change, such as moving to a "TOTEX" model as is used in the United Kingdom, which provides returns using a formula that takes into account both capital and O&M expenditures.

There are at least three disincentives to utilities adopting cost-effective NWAs:

- **No profits from O&M expenses:** Utilities earn profits on capital spending, not O&M spending. There is a major disincentive to adopt cost-effective NWAs as these typically constitute O&M spending.

- **Cost recovery:** The recovery of costs for NWAs does not fit well within the cost recovery and rate-making mechanisms. For instance, there is no mechanism to capture variances in costs and accounting treatment when a utility decides to meet a need through an NWA instead of traditional infrastructure investment.

  Distributors receive a capital envelope (e.g. over 5 years) that they use to meet system needs based on a distribution system plan ("DSP"). However, projects in the second half of the DSP term have generally not been designed yet and may be ones that could be achieved more effectively by NWAs. However, there is no mechanism to move costs from the capital envelope to the O&M envelope.

  In addition, an NWA may cost more in distribution rates but achieve greater overall benefits to customers through lowered commodity costs (e.g. by reducing energy use through efficiency). There is a disincentive to selecting this NWA even though it is in the interests of customers as it will use up a greater portion of the capital envelope.

- **Uncertainty and internal expertise:** Utilities are regulators are experts with respect to traditional infrastructure solutions. NWAs are different and therefore appear risky and uncertain to some utilities.

Removing these disincentives will require, at a minimum, the following three elements:

1. Making the utility agnostic between capital spending on traditional infrastructure and O&M spending on NWAs;

2. Adjusting rate-making mechanisms to capture cost and accounting treatment differences arising from utilities adopting NWAs in between rebasing applications (e.g. variance accounts); and

3. Regulatory oversight and accountability mechanisms, such as requirements to make all distribution system needs public in ten year plans and invite third parties to propose more cost-effective NWAs.

Incentives are needed

Utilities do not require incentives to make NWAs *more* profitable than traditional infrastructure investments. However, they do require incentives to ensure that NWAs are as profitable as traditional infrastructure investments. Without this, utilities will continue to have an incentive to adopt traditional solutions even where they are not in the interest of customers.

Selecting the incentive

For the first stage, Environmental Defence supports any approach that includes the three elements listed above. For instance, to make the utilities agnostic between capital spending and O&M spending on NWAs, utilities could earn an amount that is equivalent the return they would have earned were they to have implemented the infrastructure alternative, subject to any adjustments necessary to fairly reflect the different nature of the spending.

In addition, rate-making mechanisms could be adopted in stage one to capture cost and accounting treatment differences arising from utilities adopting NWAs in between rebasing applications (e.g. variance accounts). Environmental Defence also recommends regulatory oversight and accountability mechanisms. For instance, utilities should be required to:

1. Adopt NWAs where they are the most cost-effective;
2. Provide robust analysis of projects above a certain threshold to show that NWAs were considered; and
3. Make all distribution system needs public in ten year plans and invite third parties to propose more cost-effective NWAs.

These stage one changes all include adjustments to the current rate-making mechanisms. However, there are also options that involve fundamental changes, such as the "TOTEX" approach taken in the United Kingdom. Those are worth considering, but only once an interim solution is in place. We therefore recommend that those fundamental changes be considered as part of a second stage.

Ensuring distribution planning is informed by DER adoption

Discussion question six asks: "What should the OEB consider when setting expectations to ensure distributors appropriately consider DER adoption when planning and operating their systems (e.g., industry guidance, additional filing requirements for Distribution System Plans, new requirements for reporting and sharing information)?"

Environmental Defence recommends that distributors be required to consider steps that they can take to cost-effectively mitigate electricity system constraints that prevent their customers from implementing DERs. This includes short circuit, thermal, and voltage-related constraints. Progress is needed on this issue because capacity constraints are a major problem for individual customers and for the electricity system as a whole:

- First, these restrictions prevent customers from implementing DERs that could provide them with benefits and lower their energy bills (e.g. bi-directional electric vehicle charger for backup and load-shifting to take advantage of time-of-use rates).

- Second, these restrictions can prevent cost-effective distributed energy resources that can lower overall energy bills through reduced distribution, transmission, and generation costs.

Distributors have an important role to play in determining the magnitude of the problem (e.g. what percent of their customers cannot implement a DER due to system constraints) and in either implementing or facilitating solutions. For instance, many solutions involve telecommunication devices that prevent DERs from operating when certain conditions are met. Customers cannot implement this solution without involvement of the distributor.

This problem cannot be left entirely to customers implementing DERs. Some of those customers are large and sophisticated and able to invest in expensive project-specific solutions. However, DERs will increasingly be implemented by residential customers in small installations that clearly cannot afford expensive solutions like transfer trip. Utilities need to play a role in mitigating capacity constraints for these customers in particular.

For instance, the IESO estimates that residential vehicle-to-grid technology could provide between 65 MW to 955 MW in capacity by 2032.[12] This only includes the achievable potential, which accounts for current market barriers, and excludes mass market rate-driven non-utility-controlled solutions.[13] An example of this technology is the new Ford F-150 Lightning, which can feed back into a home from its large battery to offset the home's peak electricity demand or even export back into the grid at peak times. Utilities should not be telling customers who want the backup power and electricity savings from this vehicle that they cannot do so because the distribution system cannot handle it. Nor should utilities represent a barrier to using vehicle-to-grid technology to provide cost-effective capacity in IESO procurements.

Furthermore, it is important to be considering these constraints as soon as possible to ensure that the most cost-effective solutions can be implemented. There are potential options to explore that do not involve expensive infrastructure upgrades. For instances, utilities can explore:

- Telecommunication between customers to allow capacity to be "shared" by ensuring that the DERs are not generating and/or exporting to the grid at the same time;

- Telecommunication or control devices between customers and the utility to send a signal to a DER to switch off when certain grid conditions are met (e.g. if load is low and generation is high, or depending on the state of other neighboring DERs);

- Smart inverter settings;

- DER export control and export throttling

[12] IESO, *DER Potential Study, Final Results Presentation*, June 22, 2022, p. 24 (link).
[13] *Ibid*., pp. 13 & 24.

- Better coordination or telecommunication with DERs participating in the ISI program to allow capacity taken up by those DERs to be utilized by other DERs (DERs participating in the ISI program may only operate for a few hours a year but take up capacity for 8760 hours in a year);
- Updated planning assumptions;
- Enabling infrastructure investments; and
- Other measures discussed in the literature, such as reports by the Interstate Renewable Energy Council (IREC).

Proactive planning will help to ensure that constraints to connecting DERs are mitigated where that is cost-effective and will help to identify the most cost-effective solutions.

Next steps: policy consultation or generic hearing

Environmental Defence recommends that the next steps for the Framework for Energy Innovation be achieved through an approach that more closely resembles an OEB policy making consultation, with some adjustments to increase expert and stakeholder input, or a generic hearing. Although the stakeholder working group model is excellent for some purposes, it does not lend itself to the development of complex policy changes because it lacks an efficient decision-making mechanism.

Policy consultation approach: If the OEB were to pursue a policy consultation we would recommend the following steps to increase stakeholder and expert input:

- Retain an independent expert consultant to develop recommended policy options;
- Provide opportunities for stakeholder input before the consultant begins the work, when draft recommendations are complete, and before the OEB makes a decision on the final report.

Generic hearing: Environmental Defence is wary of a generic hearing as this could take a considerable amount of time. However, a generic hearing could be a good approach to phase two issues after initial guidance has been provided to utilities to allow them move forward in the interim. The major benefit of a generic hearing is that the OEB would benefit from more than one expert and a more rigorous exploration of the issues.

Conclusion

The OEB has an incredibly important role to play in the implementation of DERs that can lower energy bills. This includes removing the disincentives for distributions to implement NWAs as well as ensuring that distribution systems do not act as a constraint on customers seeking to lower their energy bills with DERs and the IESO seeking to procure cost-effective capacity with DERs. Environmental Defence strongly supports the OEB's focus on these important issues and asks that it adopt the recommendations outlined above.

Appendix A
NSPM excerpt re limitations of the rate impact measure (RIM)

Per National Energy Screening Project, *National Standard Practice Manual For Benefit-Cost Analysis of Distributed Energy Resources*, August, 2020, page. A-4 (link):

Limitations of the RIM Test for assessing the cost-effectiveness of DERs include the following reasons:

- Cost-effectiveness analyses should account for only future, incremental benefits and costs, as required by the Conduct Forward-Looking, Long-term, Incremental Analyses principle. The RIM Test accounts for sunk costs (i.e., lost revenues) and as such is inappropriate to use for benefit-cost analysis.
- The RIM Test attempts to answer two different questions in a single analysis, which conflates the two questions and thus does not answer either one.
- The RIM Test does not provide useful information about what happens to rates, in terms of the magnitude of impact, as a result of DER investments. A RIM benefit-cost ratio of less than one (1.0) indicates that rates will increase (all else being equal) but does not inform the extent of the rate impact—either in terms of the percent (or ¢/kWh) increase in rates or the percent (or dollar) increase in bills. In other words, the RIM Test results do not provide any context for regulators and stakeholders to consider the magnitude and implications of the rate impacts.
- Application of the RIM Test will not result in the lowest cost to customers. Instead, it may lead to the lowest rates (all else being equal). However, achieving the lowest rates is not the sole or primary goal of DER planning. Maintaining low utility system costs, and therefore low customer bills, may warrant priority over minimizing rates.
- Application of the RIM Test can lead to perverse outcomes. The RIM Test can lead to the rejection of significant reductions in utility system costs to avoid what may be insignificant impacts on customers' rates. For example, a DER might offer millions of dollars in net benefits under the UCT (i.e., net reductions in utility system costs) but be rejected as not cost-effective if it fails the RIM Test. It may well be that the actual rate impact would be so small as to be unnoticeable. Rejecting such large reductions in utility system costs to avoid de minimus rate impacts is not in the best interests of customers overall.
- Lastly, the RIM Test results can be misleading. For a DER investment with a RIM benefit-cost ratio of less than one (1.0), the net benefits (in terms of present value dollars) will be presented as negative benefits. A negative net benefit implies that the DER investment will increase costs. However, as described above, the costs that drive the rate impacts under the RIM Test are not new incremental costs associated with DERs. They are existing costs that are already in current electricity or gas rates. Any rate increase caused by lost revenues would be a result of recovering those existing fixed costs over fewer sales, not as a result of incurring new costs. However, utilities and others frequently present their RIM Test results as negative net benefits, implying that the DER investment will increase costs, when in fact it will not.