AEE INSTITUTE

August 21, 2015

<u>VIA ELECTRONIC FILING</u>

Hon. Kathleen H. Burgess
Secretary to the Commission
New York State Public Service Commission
Empire State Plaza, Agency Building 3
Albany, New York 12223-1350

Re: Case 14-M-0101 – Proceeding on Motion of the Commission in Regards to Reforming the Energy Vision

Dear Secretary Burgess:

The Advanced Energy Economy Institute (AEEI), on behalf of Advanced Energy Economy (AEE), the Alliance for Clean Energy New York (ACE NY), the New England Clean Energy Council, and their joint and respective member companies, submit for filing these Initial Comments to the *Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding,* in the above-referenced proceeding.

Respectfully Submitted,

Ryan Katofsky
Director, Industry Analysis

Comments on Staff White Paper on Benefit-Cost Analysis in the Reforming the Energy Vision Proceeding
(Case 14-M-0101)

Advanced Energy Economy Institute
Alliance for Clean Energy New York
New England Clean Energy Council

Introduction

The mission of Advanced Energy Economy Institute (AEEI), the charitable and educational organization affiliated with Advanced Energy Economy (AEE), is to raise awareness of the public benefits and opportunities of advanced energy. As such, AEEI applauds the New York Commission for opening this proceeding on Reforming the Energy Vision (REV), which seeks to unlock the value of advanced energy so as to meet important state policy objectives and empower customers to make informed choices on energy use, for their own benefit and to help meet these policy objectives.

In order to participate generally in the REV proceeding and respond specifically to the Staff White Paper on Benefit-Cost Analysis in the Reforming the Energy Vision Proceeding ("BCA White Paper"), issued on July 1, 2015, AEEI is working with AEE and two of its state/regional partners, the Alliance for Clean Energy New York (ACE NY) and the New England Clean Energy Council (NECEC), and the three organizations' joint and respective member companies to craft the comments below. These organizations and companies are referred to collectively as the "advanced energy community," "advanced energy companies," "we," or "our."

AEE is a national business association representing leaders in the advanced energy industry. AEE supports a broad portfolio of technologies, products and services that enhances U.S. competiveness and economic growth through an efficient, high-performing energy system that is clean, secure and affordable. ACE NY's mission is to promote the use of clean, renewable electricity technologies and energy efficiency in New York State, in order to increase energy diversity and security, boost economic development, improve public health, and reduce air pollution. NECEC is a regional non-profit organization representing clean energy companies and entrepreneurs throughout New England and the Northeast. Its mission is to accelerate the region's clean energy economy to global leadership by building an active community of stakeholders and a world-class cluster of clean energy companies.

Comment Highlights

The advanced energy community strongly supports the efforts of the Commission in this proceeding, and is committed to playing its part to create a high-performing electricity system in New York State. To that end, the advanced energy community looks forward to its continued involvement in this proceeding, and in assisting the Commission in this endeavor. In this section we provide a brief summary of our comments on the BCA White Paper. Our detailed comments follow below.

- We support the general framework as described in the BCA White Paper as well as the principles listed on pages 3-4, but we do not support the use of the RIM test. The Commission should consider other options for evaluating customer bill and rate impacts.
- The BCA White Paper lacks details on how the BCA Framework would be applied. The application of the BCA Framework to actual utility investments and tariff development should be addressed more fully in the final BCA Framework.
- We support uniform application of the BCA to utility investments *and* tariff development, since tariffs for DER products and services can directly offset utility investment.
- We strongly support inclusion of societal values in the BCA Framework and the use of a Societal Cost Test (SCT) as the primary measure through which the BCA Framework is applied, as this is most consistent with the goals of REV.
- Similarly, for the SCT, we support the use of a societal discount rate, not the utility weighted average cost of capital (WACC), as has been proposed in the BCA White Paper.
- We recommend that utilities be directed to assess a portfolio that considers all cost-effective energy efficiency.
- We support development of utility-specific BCA Handbooks through a collaborative, transparent process, and that the same BCA approach and basic assumptions be used by all utilities.
- We generally agree with the list of benefits and costs to be included, but recommend additions for distribution system voltage management and power factor improvement, avoided T&D investments for resiliency enhancement, and avoided noise and odor pollution.
- We respectfully disagree with Staff's assessment of the wholesale market price impacts of DER and recommend that with proper assessment, this benefit should be included and will likely be significant.

- We support Approach #2 to the valuing of emissions benefits, which is designed to estimate actual marginal damages from emissions. We do not support alternatives based on other programs or policies that were not designed to estimate actual damages, even if they are intended to reduce emissions.
- We support the addition of other externalities, such as land and water use impacts.
- We do not support Staff's approach to non-energy benefits (NEBs), which we deemed insufficient. These benefits are real and important, particularly to low and moderate income customers. A body of literature exists on this topic and other states have included them. The Commission should direct Staff to develop a more complete and rigorous approach for including NEBs in the BCA Framework.

Full Comments

Introduction

The advanced energy community supports the general framework as described in the BCA White Paper as well as the principles as listed on pages 3-4, with one key exception. As we wrote in our comments on the Track One Straw Proposal, and as described in more detail in the study that AEEI commissioned from Synapse Energy Economics[1] (included as Attachment A and referred to subsequently here as the "Synapse BCA Report"), we do not support the use of the RIM test. As the Synapse BCA Report noted (at page 15), "The RIM test suffers from many fundamental flaws and does not provide the Commission and other stakeholders with information necessary to assess rate impacts or the distributional equity issues that go along with them. Other approaches are much better suited for assessing rate impacts." We urge Staff to review the details provided in the Synapse BCA Report and consider alternatives to the RIM test for quantifying customer rate and bill impacts.

Although we recommend that the RIM test not be used, should it be included in the final BCA guidance, we recommend that it be used with caution and not be used in isolation for decision-making. Moreover, given that the goals of REV are largely related to societal benefits, we recommend that the Societal Cost Test (SCT) be given more weight and be used as the primary test for the BCA Framework. With that said, we also recommend that the final BCA guidance include more details on how the different benefit-cost tests are to be used in actual utility decision-making, investing, planning and tariff

[1] Woolf, T., et al, *Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits*, September 22, 2014.

development. The BCA White Paper did not provide sufficient guidance on how the BCA Framework is to be implemented.

Role of the BCA Framework in REV Implementation

We understand that the REV BCA Framework is being developed mainly to inform initial DSIP filings, and we support Staff's position that it should evolve over time to account for better information, tools, and grid capabilities. Nevertheless, given the groundbreaking nature of REV, we view the proposed Framework as being relatively conventional, and we would have liked to see Staff take a more innovative approach, particularly with respect to providing more guidance on how to quantify the full range of benefits and costs, such as non-energy benefits. We envision the BCA framework becoming an important part of REV implementation, and being closely tied to the development of the Earnings Impact Mechanisms (EIMs) and the Scorecards that are currently the subject of the Track 2 effort (i.e., the BCA, EIMs and Scorecard are all designed to direct utility/DSP activities that will drive achievement of the various REV objectives).

We strongly support inclusion of societal values in the BCA Framework, especially since many REV goals are societal in nature. Similarly, we strongly support use of full lifecycle analysis, since the benefits of distributed energy resources (DER) accrue over time, and many DER options are characterized by initial up-front investments followed by low or zero operating costs. However, Staff has also suggested that when utilities develop tariffs, strict application of the BCA may not be warranted because tariffs are relevant over a shorter timeframe compared to utility investments, which are a longer-term proposition. But tariffs are a critical tool that utilities can use to encourage greater use of DER for customer <u>and system</u> benefits. If the use of tariffs results in customers or third parties deploying DER assets that in turn avoid or defer utility investments, then this distinction between tariff-driven outcomes and utility investments may not be appropriate.

The Track Two Straw Proposal clearly articulates that a key objective of the Commission is to update ratemaking and utility revenue/earnings mechanisms in order to eliminate the bias towards utility capital investment.[2] Since the use of BCA is closely tied to utility investment decisions, a less comprehensive application of the BCA framework to tariff-based options may undervalue DER that is responding to such a tariff, by excluding longer-term benefits. This seems inconsistent with the full lifecycle approach supported by Staff. We therefore recommend that Staff reconsider this distinction.

---

[2] State of New York, Department of Public Service, Case 14-m-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. *Staff White Paper on Ratemaking and Utility Business Models,* July 28, 2015.

In addition, Staff suggests that tariffs may need to be "dynamic" and "self-adjusting". While we understand why this may be necessary to reflect the changing values of DER over time, we also note that, just like utilities, DER providers and customers will be making business and investment decisions, and that dynamic tariffs may introduce a level of uncertainty that discourages the very DER deployment the Commission is looking to support. At the same time, tariffs that reflect hourly wholesale prices provide some DER providers with greater opportunities to maximize benefits – in essence, participating in wholesale energy and ancillary services markets. Given these considerations, Staff should carefully assess what dynamic tariff options make sense, how dynamic tariffs will be applied, how often they will be updated, and how much they may change when they are updated. A simple analogy is that of feed-in-tariffs (FITs) for distributed renewable energy. With FITs, DG owners are assured of a fixed, long-term per kWh price for the DG output, which allows them to commit capital and secure attractive financing terms. But year over year, the value of the FIT offered to new installations may decline to reflect market maturation and technology cost improvements, striking a balance between supporting past investments while not "overpaying" for new investments.

We recognize that the goal of the BCA is to estimate the benefits and costs of DER to the distribution system, and to apply this in a manner that is market-driven and unprecedented. As a result, the geographic and temporal aspects of some of this are expected to be quite complex. It may therefore be difficult to have precise calculations, and that simplifying assumptions and approaches will be needed to enable practical application of the BCA. These simplifications, where needed, should err on the side of achieving REV's key objective of using DER to meet customer and system needs. Over time, the BCA Framework will evolve and become more sophisticated, but in the near term, the BCA should not serve as a barrier to DER deployment.

The Framework Order specifically stated that utility energy efficiency programs would be one of the four categories of utility expenditure to which the BCA Framework will be applied (Framework Order, p. 123), and the White Paper reiterates that this BCA Framework should inform decision-making with respect to utility DER investment versus traditional utility investments. Utility energy efficiency programs are a key DER investment that should be addressed in DSIP filings, and we propose that the Commission direct utilities to apply this BCA Framework to a portfolio of energy efficiency offerings that would capture all cost-effective energy efficiency opportunities. The "all cost-effective" energy efficiency should start with the 2014 NYSERDA study, *Renewable Energy and Energy Efficiency Potential Study,* which identified a statewide energy efficiency economic potential of nearly 92,000 GWh of electricity and more than 320 TBtu of natural gas by 2030, representing 45% and 32%, respectively, of the state's base case energy use forecast for those energy sources. The NYSERSA study further estimated that these economic energy efficiency resources have a present value (2012 dollars) net benefit of more than $100 billion.[3] While some states require utilities to pursue all cost-effect energy efficiency opportunities, we are proposing here that utilities be required to assess a portfolio that is inclusive of "all cost effective" energy efficiency; if the utilities' proposed energy efficiency investment differs from that portfolio in scale, they should be provide a rationale for that difference.

BCA Handbooks

The advanced energy community supports Staff's recommendation to create utility-specific BCA Handbooks to document the value of DER benefits and costs and characterize DER resource profiles. The Handbooks will enhance transparency around utility DER decision-making, inform the DER market of system needs, and build investment certainty among DER market participants. Additionally, the Handbooks should be updated periodically to reflect changing market conditions, new information and new analytical techniques.

Consistency and Transparency of DER Benefit and Cost Estimates

The BCA Handbooks should document the value of each DER benefit and cost included in the final Framework. As noted by Staff, the value of DER benefits and costs are likely to be different at each utility; however, the methodology used to calculate these values should be uniform across utilities. Additionally, any temporal or geographic variation in DER benefits and costs should be clearly documented in the BCA Handbooks. No single stakeholder has all the necessary information or expertise to develop the Handbooks. For example, advanced energy companies are in the best position to inform the process on the capabilities of their technologies and services, whereas utilities have the greatest knowledge of their systems and system needs. Determination of a statewide methodology to value DER benefits and costs should be conducted through a statewide collaborative process with the results clearly documented in the Handbooks. A consistent, transparent determination of DER benefits and costs will be a critical requirement to energize a statewide DER market.

The BCA Handbooks should be fully transparent regarding the methodologies, assumptions, and model inputs used to calculate DER benefits and costs. Transparency is particularly important when it comes to assumptions that determine avoided costs and the characterization of DER resource profiles. Transparency will facilitate constructive stakeholder conversations and lead to a more active DER market.

---

[3] An all cost-effective approach should evaluate EE portfolios using the new BCA Framework. Therefore, the 2014 NYSERDA study is a good starting point, but may not capture the scope of an "all cost-effective" portfolio under new the BCA Framework.

Similarly, when it comes time to conduct the BCA analysis, this should also be done in an open and transparent collaborative process, perhaps with the Commission in charge. For example, allowing technology companies access to distribution planning data (subject to legitimate utility concerns over protection of customer data and grid security) will enable them to propose creative solutions. The BCA Framework should also be flexible enough to incorporate future advances that allow for the quantification of benefits or costs that are currently not easily quantified.

Characterization of DER Resource Profiles

Although the purpose of the BCA analysis is to guide utility investments and tariff development, we recognize that non-utility stakeholders also have valuable expertise that should be included in the development of the Framework. Therefore, characterization of DER resource profiles must be conducted in an open and transparent manner with significant contributions from DER providers, evaluators, and stakeholders with specific expertise. Third parties should be encouraged to bring DER technologies, applications and services to the table to be validated and included in the BCA Handbooks.

The BCA Handbooks should be inclusive of a wide range of DER technologies, but should not be considered comprehensive. Certain DER programs and technologies may have unique benefits and cost components or resource profiles that cannot be anticipated in the BCA Handbooks. Indeed, the development of a successful platform market as envisioned by the Commission will attract these types of innovative DER solutions. Additionally, new technologies or project ideas should not be required to wait until the next revision of the BCA Handbooks before they are eligible to participate in the DER market. For these reasons, the Handbooks should have the flexibility to accommodate novel or unique DER projects, technologies and services.

Interactive Benefits of DER Resources

Staff has asked for specific examples of how all benefit and cost components will be applied to an illustrative portfolio of resources, and specifically, how net benefits increase when certain technologies are used together. For example, colocation of distributed solar and flexible storage could create combined benefits that exceed the benefits of either technology individually. Other technology combinations include small wind with solar, anaerobic digester gas with fuel cells and demand response technologies with energy storage. Another, example would be the effect of home energy report (HER) programs in increasing customer participation in other DER programs and technologies. Independent evaluations of HER programs show that customers who receive HERs are at least 11% more likely to participate in additional energy efficiency programs just from general improved awareness of energy usage.[4] A comprehensive discussion of the interactive effects of DER technologies is beyond the scope of these comments, but is worth additional focus as the parties develop the final Framework, and should be documented in the BCA Handbooks.

Integrated demand-side management (IDSM) programs offer another example of interactive benefits. IDSM programs integrate energy efficiency (EE) measures with demand response (DR) technologies by providing intelligent control systems that reduce energy consumption and demand. When effectively combined as part of a comprehensive energy saving retrofit project, these systems also provide a cost-effective demand response (DR) option to initiate customer demand reduction strategies. Another example of IDSM benefits is that when behavioral demand response (BDR) is layered on top of an HER efficiency program, the peak demand savings resulting from the combined program exceed the demand savings from either the BDR program or the HER program alone.[5]

The above examples illustrate the potential complexity of this issue, but also its importance. Not all interactive effects can be known *ex ante*, but these interactive effects should be incorporated into future versions of the BCA Handbooks as they become known, and as above in regard to innovative solutions, interactive benefits that can be documented should not have to wait for inclusion in updated Handbooks before being incorporated into the BCA Framework. More generally, we believe that this issue warrants further study before the final BCA Framework is deployed.

Recognizing that the interactivity of benefits has the potential to create significant complexity in BCA analysis, another option to consider for the BCA Handbooks is that they focus on the valuation of services provided to (and needed from) the grid. This would allow the flexibility to interface with a wide range of DER combinations and solutions. Not every approach/combination would have to be covered by the BCA Framework, but rather the BCA would focus on how to value the range of possible values to the system and society, and costs of system services. To say this another way, while there will be a very large number of possible combinations of technologies and services the number and value of input services required from the grid and output services/values to the grid and society should be more limited, and could be the focus of the BCA. With this approach, the primary questions are:

---

[4] Median rate of program participation lift as measured by independent evaluations of Opower HER programs. Evaluations available at http://opower.com/company/library/verification-reports.

[5] Brandon, A., List, J., Metcalfe, R., and Price, M., *The Impact of the 2014 Opower Summer Behavioral Demand Response Campaigns on Peak-Time Energy Consumption*. June 2014. (publication forthcoming)

- To the best of current knowledge and for the time window before the next Handbook refresh:
  - What are the types of input services that might be needed?
  - What are the types of output values/services that could be provided that should be quantified?
  - What approach should be used to consistently quantify each of these?
  - What services or needs might we not know now that should be provided flexibility to adapt to until we next have a chance to make updates to the Handbooks?

Frequency of Handbook Updates

The BCA Handbooks should be updated periodically to reflect changes to the value of DER benefits and costs and as the ability to quantify additional benefits and costs increases. These updates should be conducted frequently enough to provide the correct market signals for DER market participants, but not so frequently as to create unnecessary investment uncertainty or excessive administrative burdens on the Commission, utilities, and other stakeholders. If the BCA Handbooks were updated on a regular schedule of every three, or perhaps, four years, this would create the correct market signals while accommodating a wide range of DER technologies with variable lead-times to deployment. The updates to the BCA Handbooks should be coordinated with utility rate case filings to the greatest extent possible. This will further the integration of DER into utility investment plans and ensure that utilities to use consistent assumptions and information across the range of planning activities.

Use of Sensitivity Analysis

The purpose of sensitivity analysis is to study the variations of the output of the BCA model in relation to the uncertainty of the various inputs. Sensitivity analysis is an essential tool for testing the robustness of the assumptions and results of a model, and will serve to improve our understanding of the relationships between inputs and outputs, and identify the inputs that are a greater source of uncertainty and should therefore be the focus of further research. Fuel price is an example of an input assumption subject to significant uncertainty. Another example of where sensitivity analysis may be beneficial is in looking at discount rates, which are not subject to uncertainty like fuel prices, but that have a large bearing on BCA results. For example, The BCA analysis could explore a reasonable range for a societal discount rate to test the sensitivity of proposed measures.

Discount Rates

The choice of a discount rate for DER screening tests has a significant impact on the valuation of DER. Discount rates are used to compare future streams of costs and benefits with present-day costs and benefits, determining their present value (PV). Since DER typically incurs costs in the early years while their benefits accrue over time, the choice of a discount rate is critical. A discount rate of zero values costs and benefits in future years as much as costs and benefits today; a high discount rate significantly reduces the value of costs and benefits in the later years.

The Synapse BCA Report provides an excellent overview of why the discount rate for DER under REV should reflect societal priorities and objectives, including energy savings and emissions reductions over the long term. The utility weighted average cost of capital (WACC), as suggested by Staff as the sole discount rate to use in REV, is inappropriate given that it reflects only the interests of utility shareholders, which are not coincident with the policy interests driving the investment. Furthermore, the investments will be made with ratepayer dollars; given the use of ratepayer funds and the resulting public benefits, a societal discount rate is most appropriate. The impact of this choice can be seen in the table below:[6]

Net Benefit	\$1	\$1
Years	30	30
Discount rate	3%	10%
Present Value (PV)	\$0.41	\$0.06

Accounting for Risk

Discount rates are used to account for both the time value of money (i.e., cost of capital) and the riskiness of an investment. Lower-risk investments can be discounted using a relatively low discount rate to reflect the lower level of uncertainty affecting the investment over time. For example, one of the often-overlooked benefits of energy efficiency resources is that they generally have lower financial, project, and portfolio risk than traditional supply-side resources, according to a recent paper by the Energy Efficiency Screening Coalition about reforming energy efficiency cost-effectiveness screening in the United States.[7]

---

[6] M. Sami Khawaja, Cadmus Group, presentation for U.S. EPA SEE Action webinar, "Energy Efficiency Cost Effectiveness Testing," January 16, 2014.
[7] Tim Woolf, et al, *Recommendations for Reforming Energy Efficiency Cost-Effectiveness Screening in the U.S.*, page 16-20, November 2013, Energy Efficiency Screening Coalition/Synapse Energy Economics.

As with EE, other DER options (or portfolios of DER) are likely to have similarly lower risk profiles because cost and performance are well known at the time of the investment.

Efficiency programs are often funded by either a systems benefit charge or are placed in the rate base at the time of a rate case, as mandated by legislation or the regulatory process, so there is little financial risk to the utility. In addition, energy efficiency results in lower project risk relative to the typical construction, fuel price volatility, and market risks associated with supply side resources. And finally, energy efficiency provides diversification of the energy portfolio of a utility, helping to mitigate portfolio risk. Moving forward in REV implementation we expect DER programs more broadly will exhibit similar behavior to existing EE programs.

The Energy Efficiency Screening Coalition paper also suggests that states use the discount rate as the primary mechanism to account for risk when screening energy efficiency. According to the authors, the discount rate 'allows for a relatively explicit way to address the risks associated with costs and benefits over different time periods.'

It is important to note that the choice of discount rate is a policy choice: a reflection of the weight the state wants to place on today's costs and benefits vs. those of future years. However, the utility WACC, proposed in the BCA White Paper, is considered by many experts to be too high. Properly accounting for the risk benefits of DER investments should lead to significantly lower discount rates being used.

Further, states are advised to adopt a discount rate comparable to the U.S. Treasury bill rate – about 3%. Not only does the lower rate properly reflect the lower risks, it also leads to transparency and ease of use. Different utilities in a single state can adopt the same discount rate without each having to make complicated risk adjustments. This would be a good fit with REV goals of statewide standardization among utilities to minimize market barriers and confusion. As of 2012, six states used long-term U.S. Treasury bills as the basis for setting the discount rate.[8]

More recently, in July, Maryland's Public Service Commission adopted the use of a societal cost test to evaluate energy efficiency programs, alongside the use of the Total Resource Cost (TRC) test. The commission cited its obligation to "consider a broader societal impact stemming from the implementation of EE programs" and directed the use of both tests in primary screening. As a result, because the Maryland commissioners endorsed the societal perspective for evaluating EE programs' cost-effectiveness, they were consistent in their choice of a societal discount rate (4.7%) for the societal

---

[8] Kushler, M., Nowak, S. and White, P., *A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs*, February 2012, Report Number U122, American Council for An Energy Efficient Economy.

screening. They also maintained the use of the individual WACC for each utility as the assumed discount rate for the purposes of the TRC test. Thus, the Maryland commission approved both tests and their appropriate discount rates as "equally valid." Similarly, New York State could consider the use of the utility WACC for the UCT, along with an appropriate societal discount rate for the SCT, although as we have stated above, the SCT should be the primary test used in the BCA.

Benefits and Costs Included in the Proposed Framework

We list here our proposed additions to the benefits and costs included in Table 1 of the BCA White Paper. The subsequent section, *Proposed Methodology for Valuing Benefits and Costs*, provides additional information on these proposed additions as well as items already included in the Table 1.

Bulk System

The advanced energy community supports the list of benefits included for the bulk system.

Distribution System

In addition to the benefits listed in Table 1 of the BCA White Paper, we recommend adding the following to the list of distribution system benefits:

- **Voltage management**: DER can provide distribution level Volt/VAR support
- **Power factor improvement**: DER can provide power factor correction to minimize VARs and the associated increased current required from the grid

Reliability/Resiliency

In addition to avoided restoration and outage costs, we believe the following benefits should be included under Reliability/Resiliency:

- **Avoided Transmission & Distribution Investments for Resiliency Enhancements:** In addition to the avoided T&D investments included under distribution system and bulk system benefits, DER can avoid the need for resiliency-specific T&D upgrades such as converting distribution feeders to an underground system.

External

In addition to those benefits listed in the BCA White Paper, Staff should include:

- **Avoided noise and odor pollution:** This results in reduced impact on local communities and faster time to market as a result of reduced permitting requirements.

Separately, we also note that Staff has lumped all of the non-energy benefits (NEBs) together in one row in Table 1. We suggest separating these into "utility" and "societal". Although all NEBs should be included in both the UCT and SCT, providing more details on this important set of benefits would be beneficial.

Proposed Methodology for Valuing Benefit and Costs

Bulk System

The advanced energy community generally supports Staff's approach for valuing benefits and costs to the bulk system, but offers the following comments:

Avoided Generation Capacity (ICAP) Costs, including Reserve Margin

The advanced energy community supports Staff's approach for valuing avoided generation capacity benefits and costs.

Avoided Energy (LBMP)

The advanced energy community supports Staff's approach for valuing avoided energy benefits and costs.

Avoided Transmission Capacity Infrastructure and O&M

In addition to the approach proposed in the BCA White Paper, Staff should recognize that building new transmission lines to relieve congestion takes time. If the affected area is already experiencing poor reliability, delaying system improvements can have indirect negative impacts on a utility's earnings. This could come in the form of penalties from the regulator, or denied rate approvals or rate increases if the utility fails to adequately serve all customers. Since DER can generally be deployed quickly in targeted areas, it can offer value to the utility beyond the direct market or transmission investment deferral benefit. In addition, DER can be deployed incrementally, thus saving excess investment in unneeded traditional infrastructure and offering reduced risk of stranded assets.

Avoided Ancillary Services

The advanced energy community recommends that Staff incorporate a historic (1-2 year) average of values of Regulation, Reserves, VSS, and Black Start payments from the NYISO and project those forward over the planning period. It should be noted that as increasing quantities of variable resources are added to the electric system and increasing quantities of end-use demand response and storage technologies are installed in homes and businesses, the benefits associated with the provision of ancillary services could increase significantly.

Wholesale Market Price Impacts

We respectfully disagree with the position taken by Staff in the "Wholesale Market Price Impacts" Section. If the theory put forward by Staff is translated into policy, it could significantly undervalue DER. Of the three alternatives put forward by Staff for valuing the wholesale market price impacts, only the second method comes close to valuing DER appropriately, and even still, it results in a large underestimation.

First, it is important to note that several independent studies have quantified the wholesale price impacts of demand response and energy efficiency, including:

1. A June 2013 presentation given by the Consumer Interest Liaison at the NYISO summarizing the capacity cost savings impact that additional demand response (Special Case Resources or "SCR") would have across the different NYISO zones. For example, despite the relatively low capacity costs in Zones A-F, 25 MW of additional SCR in the NYISO capacity market was projected to reduce capacity prices by $6.3 million in a year, or $250,000/MW. Capacity in these zones typically does not exceed $50,000/MW-year, so the total savings dwarf the cost of a comparable amount of capacity.[9]

[9] New York Independent System Operator. Consumer Impact Analysis: Provisional & Incremental ACL for SCRs. Tariq N. Niazi. Senior Manager, Consumer Interest Liaison. Joint ICAP and PRL Working Groups. June 24, 2013.

2. Reports from the PJM Internal Market Monitor that state demand response and energy efficiency saved consumers over $11.8 billion in capacity costs in the 2013-2014 Base Residual Auction,[10] and $9.3 billion in the 2017-18 Base Residual Auction.[11]

3. An April 2011 report from FERC titled "Performance Metrics for ISOs and RTOs" that states DR reduced LMPs by $0.04/MWh-$1.43/MWh in ISO-NE, $0.27/MWh for NYISO, and by $650 million in one week in PJM in 2006.[12]

4. A 2007 Brattle Group report prepared for MADRI[13] titled, "Quantifying Demand Response Benefits in PJM." Brattle found that:

   > "curtailing 3% of each selected zone's super-peak load, which reduces PJM's peak load by 0.9%, yields an energy market price reduction of $8-$25 per megawatt-hour, or 5-8% on average....the second major source of benefit to program participants is the reduction in capacity needed to meet reserve adequacy requirements for a load shape that has been modified by reducing the peaks. A very rough estimate of this long-term capacity benefit is $73 million per year for curtailment of 3% of load in the five zones."

5. The July 2013 report by Synapse Energy Economics, *Avoided Energy Supply Costs in New England: 2013 Report*, prepared for the Avoided‐Energy‐Supply‐Component (AESC) Study Group.

While economic theory may suggest that as DER reduces wholesale prices, other supply resources would not want to participate in the market, which would drive up prices and offset the initial cost savings, there is no practical evidence to suggest this has been true. In the case of PJM, where DR has had the highest penetration and largest savings, generation retirements have been traced more to natural gas placing downward pressure on energy prices, as well as stricter environmental regulations. In their 2015-2016 Base Residual Auction (BRA) report, PJM stated, "This RPM auction was impacted by an unprecedented amount of planned generation retirements (more than 14,000 MW) driven largely by

---

[10] *Analysis of the 2013/2014 RPM Base Residual Auction, Revised and Updated*, Monitoring Analytics, The Independent Market Monitor for PJM, September 20, 2010.
http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf

[11] *Analysis of the 2017/2018 RPM Base Residual Auction*, Monitoring Analytics, The Independent Market Monitor for PJM October 6, 2014.
http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf

[12] *Performance Metrics for Independent System Operators and Regional Transmission Operators.* Prepared by the Federal Energy Regulatory Commission for Congress. April 2011. Page 12.

[13] *Quantifying Demand Response Benefits in PJM*, Prepared by The Brattle Group, Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), January 29, 2007.

environmental regulations, which drove prices higher than last year's auction." Moreover, nearly 5,000 MW of generation cleared the PJM BRA in 2015-16, so clearly new entry was incented despite the price suppression effects of DR and EE. Another example is Germany, where the addition of large quantities of renewable resources has resulted in significantly lower wholesale prices – from approximately 54 EUR per MWh in early 2011, to 34 EUR per MWh in mid-2014 – in spite of the mothballing of nearly 5 GW of generation in 2013 alone.[14] The truth is that DER has reduced market power and forced new entrants to offer more competitively priced options in the market, which brings down prices for everyone. Any offset to cost savings due to lack of participation from supply are minimal. One cannot draw strong conclusions from mothballing in New York, where many resources that have been mothballed have received out-of-market contracts.

Moreover, Staff has assumed - without providing any support for the proposition – that demand is elastic (i.e., if prices go down, then demand will go up). We disagree with this conclusion and believe that this erroneous assumption will have the effect of practically eliminating the value of DER on wholesale prices. Instead, the BCA Framework could use existing models such as MAPS with some minimal adjustments to capture the true market benefits of DER. We believe, that with proper assessment, the BCA will show that DER can displace higher-cost marginal generators and thereby move lower cost generation on the margin, resulting in lower electricity prices for all customers.

Distribution System

Avoided Distribution Capacity Infrastructure

The BCA Framework primarily considers the ability of DER to reduce the need for new T&D to serve peak demand. We generally agree with the proposed approach to determine the deferred investment resulting from deploying a particular amount of capacity. However, the proposed approach does not take into account the potential for certain DER to defer investments beyond a one-to-one ratio of the DER capacity rating. In particular, DER with higher capacity factors can reduce loading on distribution equipment, such as transformers, over longer periods of time (i.e., during both peak and off-peak hours). This can reduce heating in large transformers, which increases the pre-peak temperature and allows for greater short-term peaks. This effect can be measured by referencing transformer load curves.

[14] TenneT (one of the four large German ISOs), « Market Review 2014 H1 », September 2014.

Avoided O&M

Reduced loading on distribution equipment can extend the lifetime of the equipment, thus deferring scheduled replacement costs. DER, particularly those with high capacity factors, can reduce loading on distribution equipment, which can extend lifetimes and reduce general 'wear and tear' on the system. This can have significant monetary benefits. For example, the value of transformer life extension can be estimated according to the IEEE Guide for Loading Mineral-Oil-Immersed Transformers (IEEE Standard C57.91-1995), which contains equations to calculate transforming percentage loss of life from factors such as the ratio of load to rated load. The value can be calculated based upon the reduced rate of failure/reduced O&M costs as well as the deferred replacement value.

Avoided Distribution Losses

The value of DER for reducing losses can vary significantly in different locations. Thus, it is vital that the BCA require utilities to provide distribution losses in specific regions, rather than using an average number across all locations.

As noted above, the advanced energy community recognizes that Staff included Avoided Ancillary Services benefits under the Bulk System category. However, we believe the following benefits are not appropriately captured and should be added under the distribution system benefits category:

Voltage Management (new proposed benefit)

DER can provide distribution level Volt/VAR support. This can offset alternative means for achieving Volt/VAR management and their associated costs. The associated savings can be calculated as the avoided investment for upgrades to existing Volt/VAR management equipment or the avoidance of investment in new equipment, using the fixed charge rate or the associated factors that constitute the fixed charge rate for a cash flow analysis.

Power Factor Improvement (new proposed benefit)

DER provides power factor correction to minimize VARs and the associated increased current required from the grid. Power factor improvements will incrementally reduce losses beyond load leveling or voltage management activities by utilities. The value associated with power factor improvements can be calculated by multiplying the marginal loss rate by the amount of generation produced on-site and multiplying loss estimates by the cost of energy at the LBMP. DER can also improve a customer's power factor through VAR generation, benefitting the grid by reducing additional current, which increases the grid's load carrying capability and reducing losses. Customers can benefit by improving bill management if utilities impose power factor limits and have additional charges when the power factor falls below a specified value.

Reliability/Resiliency

Avoided Restoration Costs

In addition to the examples provided in the BCA (automated feeder switching and improved diagnosis and notification of equipment conditions), it is important to note that individual DER units can reduce restoration costs. DER with the ability to isolate from the grid in the event of an outage can:

1. Keep a portion of the distribution grid online and islanded from the broader outage, thereby reducing cold load pickup and avoided restoration costs in the area.
2. Decrease the cost and increase the speed of restoration to other parts of the utility distribution system, due to the avoided need to address a local area supported by the DER.
3. Provide services to support other parts of the distribution system as power is restored (i.e., Volt/VAR, black start from a live distribution circuit)

In addition, DER without grid-islanding capability can provide option value for microgrid build-out in the future without incremental DER capacity investment.

Avoided Outage Costs

The estimated cost of outages should include the impact of outages on the utilities SAIFI and CAIDI index rankings. There are also qualitative impacts such as customer satisfaction. Total avoided outage costs can be calculated as [Probability Weighted Avoided Outage Time] * [(Total Utility Outage Cost Per Outage Hour) + (Total Customer Cost Per Outage Hour)]. This formula could be adjusted to account for utility reliability penalties that are of fixed values or specific to a number of instances rather than time. However, to omit a portion of the formula entirely would likely understate the avoided cost of outages.

The BCA should be sure to include the potential avoided loss of utility revenue during outages. If DER owned by the utility or contracted by the utility via a lease or PPA continues to receive a revenue stream when an upstream outage occurs, the utility can continue collecting revenue during outages. This is a new area for the utility to gain additional value and it is not currently actively considered as part of current rate structures. Utilities could estimate avoided loss of revenue by multiplying the size of load supported by DER by the duration of potential outages. The average value can be determined utilizing historical data on number of outages, outage size and duration over a time period. A simple calculation would be:

*Avoided loss of revenue = size of load supported by DER during an outage * duration of outage * retail rate*

Avoided Transmission & Distribution Investments for Resiliency Enhancement (new proposed benefit)

We recommend adding this category under resiliency benefits. In addition to the avoided T&D investments included under distribution system and bulk system benefits, DER can avoid the need for resiliency-specific T&D upgrades such as converting distribution feeders to an underground system.

External

We urge Staff to employ a rigorous and thorough approach to estimate the out-of-market public costs and benefits that DER impose or provide. To the extent feasible, this methodology should be inclusive of the range of externalities impacted by DER and should seek to measure the actual benefits or costs resulting from the deployment of DER rather than relying upon other markets developed for different purposes (e.g., RGGI, RPS RECs).

With respect to SO_2, NOx, and CO_2, we find that the Staff's proposed Approach #2 provides the most appropriate framework. Specifically, the use of the CARIS model and database to calculate the change in the tons produced of each gas by the bulk system when system load levels are reduced provides a framework to enable a precise estimate of the actual emissions reductions resulting from DER deployment. Considering that different DER technologies have different operational characteristics, it is important that the CARIS model measure the avoided emissions from the marginal bulk generators at different hours of the year. In addition, the CARIS model must take into account the effect of line losses – that is, one MWh produced by DER will actually avoid the generation of more than one MWh from a centralized generator.

We also support the use of the EPA damage cost estimates for SO_2, NOx, and CO_2. While these estimates may not be precise and in fact likely underestimate the marginal damage costs, they appear to be the most robust available. It would not be reasonable for the DPS to conduct an independent assessment of the damage costs, and therefore we support using the EPA's estimate as the most accurate estimate possible. As suggested in the BCA White Paper, the ton/MWh emissions reduction from each

DER calculated by the CARIS model should be multiplied by a \$/ton value of marginal damage costs provided by the EPA.

In the case of emission-free DER, we support applying this estimate as a \$/MWh adder, net of the costs already internalized by CARIS, when comparing to bulk energy sources. However, regarding DER that emits quantities of these gases, we disagree with the proposed approach to add the full marginal damage cost estimates to the DER's pecuniary costs per MWh. Instead, the difference between the emissions resulting from the DER and the emissions avoided from bulk energy sources should be calculated, and then the appropriate 'net' adder should be applied to the DER. For example, if a DER emits 0.2 tons CO_2/MWh, and the bulk sources it avoids emit 0.5 tons CO_2/MWh, then the DER should be credited at 0.3 tons CO_2/MWh times that estimated \$/ton value of marginal damage costs.

We do not support Staff's suggestion, out of concern regarding inaccuracy of production models, to add no additional social value for SO_2 and NOx to the CARIS LBMP compliance forecasts. Staff's concern that the MAPS data may not be accurate enough to be relied upon is valid, but should not be used as justification for overlooking this important externality. One alternative is for DPS to adopt a standard assumed SO_2 and NOx emissions rate of the marginal generators on the bulk system, and use this number to calculate the ton/MWh reductions from DER. For example, the EPA eGRID database publishes non-baseload emissions rates of 0.6647 lbs/MWh NOx and 0.1156 lbs/MWh SO_2 for NYC/Westchester, 1.0904 lbs/MWh NOx and 0.6610 lbs/MWh SO_2 for Long Island, and 0.8264 lbs/MWh NOx and 2.3687 lbs/MWh SO_2 for upstate NY.[15] These numbers, adjusted for appropriate line losses, could be adopted in order to provide a reasonable estimate of this important externality without relying on highly sensitive production models.

As stated above, we support Staff's proposed Approach #2. We do not support Approach #1 for the following reason: As mentioned in the BCA White Paper, the CARIS estimates "were never intended to be an estimate of the full marginal damage costs"[16] and therefore cannot be relied upon to develop an efficient market. While these values represent the NYISO's best estimate of the compliance prices under RGGI, there is no analytical connection between these values and societal costs (i.e., actual damage costs) of CO_2 emissions. Similarly, we do not support proposed Approach #3, which would also apply a value that was not intended to measure the marginal damage costs of emissions (namely, the RPS \$/MWh REC value). The state's willingness-to-pay for large-scale renewable (LSR) energy over the last 10 years is not the same as the value of avoided CO_2 emissions. Going forward, under a new LSR Program, this value will be most related to natural gas prices if a bundled PPA approach is used, rather than any estimate of

[15] http://www.epa.gov/cleanenergy/documents/egridzips/eGRID_9th_edition_V1-0_year_2010_Summary_Tables.pdf.
[16] BCA page 32

the marginal damage costs of emissions. Under Approach #3, when LSRs reach parity with non-renewable generation, the assumption would be that the price of carbon should be zero, which certainly will not be the case. Furthermore, we share Staff's concern that this approach "would ignore the differences among emitting DERs, for example, the different impacts of combined heat and power generation as compared to diesel generation."[17] Rather, the selected approach should treat emitting and non-emitting DG differently, and account for differing emission levels.

For technologies that help with methane mitigation, methane emissions should be valued on a CO_2-equivalent basis. For example, the value of methane mitigation from organic waste diversion from a landfill to anaerobic digestion should be credited appropriately.

In addition to SO_2, NOx, and CO_2, it is important that the BCA include other environmental benefits. These include:

- **Avoided Land Resource Impacts**: This could include avoided real estate costs, which can be calculated by multiplying the local prevailing cost of real estate by the avoided acreage, calculated by comparing the land needed to develop the DER in comparison to the alternative generation and distribution capacity. It is particularly important to value impacts on open space and/or recreational resources in areas where such resources are scarce, such as densely populated urban areas.
- **Reduced Water and Sewerage Use**: DER may displace generation from thermal plants that withdraw and use significant water resources. The quantity of avoided water consumption and withdrawals can be calculated by identifying consumption and withdrawal rates of the marginal plants whose output is reduced in response to the reduction in demand, and multiplying this by the total MWh of avoided generation, and then subtracting the total water used by the DER. Certain efficiency measures also reduce end-use consumption and sewerage of water.
- **Water Quality Benefits**: In addition to the avoided consumption or withdrawal of water, DER can avoid the discharge of water from centralized thermal power plants. Water discharge can be calculated by subtracting the consumption from withdrawal. Water discharged by combustion-based power plants is often hot and can be polluted, damaging marine and aquatic ecosystems and fisheries, both of which provide economic and societal

[17] BCA White Paper, page 41.

value. This value can be calculated based upon the avoided cost of restoration of these ecosystem services if damaged.

- **Other Heating Fuel Benefits:** Certain efficiency measures can have the co-benefit of reducing non-electric, non-gas heating fuels, including propane, fuel oil, and wood. For example, a home weatherization program that targets reduction in air conditioning load will also reduce fuel oil consumption in a household that heats using fuel oil.
- **Noise and Odor Pollution Benefits:** This results in reduced impact on local communities and faster time to market as a result of reduced permitting requirements.

Non-Energy Benefits

Non-energy benefits (NEBs) can be difficult to quantify, but research shows that these benefits are not zero and thus need to be considered when calculating costs and benefits of DER. We are disappointed that Staff chose to simply provide a short paragraph on non-energy benefits, despite the existence of a body of literature on the topic and reference to the importance of non-energy benefits in previous comment filings in the REV proceeding. Staff then simply suggested that utilities "recognize" impacts and "weigh their impacts, quantitatively, when possible, and qualitatively, when not." Noted researcher on non-energy benefits, Dr. Lisa Skumatz, succinctly describes the problem with the practice of avoiding the quantification of non-energy benefits:

> The regulatory tests are designed to assess costs and benefits, but protocols omitted some benefits, presumably because reliable values were not available. This leads to computational bias in benefit-cost ratios (from the omission of net benefit categories, but not omission of costs), and as a result, bias in decision-making using these ratios. Zero is the wrong proxy value; research has proceeded, and the results for a number of subcategories of NEBs can be properly reintroduced into these regulatory tests. Revising the tests (TRC, Societal Tests, or whichever others best reflect the state's energy goals) and incorporating subsets of NEBs reduce sources of bias in program and portfolio decision-making, and more appropriately directs the investment of millions of public or shareholder dollars.[18]

Within the context of REV and the goal of market development and accurate valuation of DER, it is critical to explicitly include NEBs in the BCA Framework. Lenders themselves are acknowledging the importance of documenting NEBs as well as energy savings to help support underwriting practices for

[18] Skumatz, L., Non-Energy Benefits/Non-Energy Impacts (NEBs/NEIs) and Their Role & Values in Cost-Effectiveness Tests: Maryland, March 31, 2014

investments in DER.[19] State policies that help further progress, rather than hinder it, will help achieve REV goals. To achieve a robust, symmetrical, and transparent accounting of costs and benefits of DER, including EE, New York will have to devise an approach for valuing hard-to-quantify attributes. The Synapse BCA Report identified a number of strategies to approximate value when straightforward calculation is difficult, including proxies, benchmarks, regulatory judgment, and weighting and scoring (multi-attribute decision analysis), all considered from the utility, participant, and societal perspectives. The Synapse BCA Report also pointed to the work of the National Efficiency Screening Project, which developed the Resource Value Framework (RVF) as an innovative approach to cost-effectiveness testing. The RVF suggests that DER investments be evaluated through the lens of the public interest, incorporating state policy goals explicitly as part of the inputs and outcomes. The difficulty of quantifying non-energy benefits is no reason to balk at the challenge; indeed, there would be no REV if New York was afraid of complexity and it is a disservice to the Vision to fail to account for non-energy benefits.

Using energy efficiency as an example – given that most consideration of DER benefits to date relate to energy efficiency – ACEEE recommends that, as a best practice, program administrators should include all benefits of implementing energy efficiency as a utility resource.[20] In its paper, ACEEE found that only Rhode Island, New York, and Massachusetts explicitly calculate utility-specific NEBs. Other states adopted percentage adders to account for NEBs without actually quantifying them. The table below, from the ACEEE paper, summarizes states that adopted the adder approach.

Examples of Non-energy benefit adders (from ACEEE, 2015)

State/company	Non-energy benefit adder
Colorado	10% (25% for low-income programs)
Iowa	10%
DC	10%
Vermont	15%
PacifiCorp	10% for low income (CA, ID, OR, UT, WA, WY)

Massachusetts undertook a study in 2011 to help determine the basis for estimating non-energy benefits by utility. Almost all of the utility NEBs examined related to results from low-income programs; the study assigned values per participant per year for several benefits, as shown in the table below, which shows interesting and important utility outcomes.

---

[19] Deutsche Bank, *The Benefits of Energy Efficiency in Multifamily Affordable Housing: supporting the health & vitality of affordable housing, building residents & the greater economy*, January 2012.

[20] *Everyone Benefits: Practices and Recommendations for Utility System Benefits of Energy Efficiency*, Brendon Baatz, June 2015, American Council for an Energy-Efficient Economy.

Massachusetts utility NEB value recommendations ($/MWh) (from ACEEE, 2015)

NEB	Annual value
Arrearages	$2.61
Bad debt write-offs	$3.74
Terminations and reconnections	$0.43
Customer calls	$0.58
Collections notices	$0.34
Safety-related emergency calls	$8.43

In the Maryland order mentioned above, issued July 16, 2015, the Commission went further than most states when it ordered the inclusion of non-energy benefits as quantified by Itron for the Maryland Energy Administration. These include:

- Non-energy avoided air emissions benefits ($0.002/kWh saved)
- Non-energy comfort benefits ($34/year for insulation and duct-sealing installation through the MD Home Performance with ENERGY STAR program)
- Non-energy commercial and industrial operations and maintenance benefits (varies by utility)
- Non-energy 2% increase in benefits associated with reduce customer arrearages in low-income portfolio

As alluded to in the foregoing discussion, non-energy benefits from DER are particularly relevant for low-income households where, for example, energy efficiency often contributes substantially to improved health and comfort. Therefore, not adequately considering these benefits could perpetuate unequal access to DER and be detrimental to the populations who bear a disproportionate burden of the costs of our current energy system. For example, a recent DOE report found substantial non-energy benefits from energy efficiency in low income homes: "…WAP [weatherization assistance program] achieves more than helping low-income households lower their energy bills… With health and safety benefits and costs included, the benefit cost ratio rises to 4."[21] While non-energy benefits are often divided into societal NEBs and utility NEBs, further granularity is sometimes used when evaluating multifamily buildings where there are specific and distinct NEBs for tenants and owners, some more easily quantifiable than others but certainly not zero.[22]

In addition to the references included in the footnotes above, some additional potential sources of information relevant to NEBs include:

---

[21] http://energy.gov/eere/articles/getting-it-right-weatherization-and-energy-efficiency-are-good-investments)

[22] Elevate Energy, *Preserving Affordable Multifamily Housing through Energy Efficiency: Non-Energy Benefits of Energy Efficiency Building Improvements*, January 2014

- Health Care Without Harm (https://noharm.org/)
- Energy Impact Calculator (EIC) http://eichealth.org
- A recent article in The Lancet[23] about the health impacts of climate change

Participant DER Costs

Staff suggests using a simplified approximation (based on what ConEdison uses for its DR program) that participant opportunity costs are 75% of any incentives paid to participants. This value is not supported by empirical research and therefore cannot be recommended as a proxy for participant cost. Given the expanded scope envisioned for DER moving forward, and the range of DER technology and service options that will be considered, this simplification may not be sufficient. Participant costs are very hard to quantify, and some level of approximation will likely be needed, but a more nuanced approach is likely justified.

Lost Utility Revenue

Staff states that even though there is decoupling in New York, "bill impacts on non-participating customers should be considered for the purposes of determining the ratepayer impact measure of a project or program." As we have noted above, we do not support the use of the RIM test. Rather, the Commission should consider alternatives to the RIM test for evaluating rate and bill impacts.

Utility shareholder incentives

We support the inclusion of shareholder incentives in program costs.

Net non-energy costs

Staff has asked for inputs on these to the extent they are not included in other costs. We support the inclusion of non-energy costs only if non-energy benefits are also included.

Conclusions

The advanced energy community strongly supports the efforts of the Commission in this proceeding, and is committed to playing its part to create a high-performing electricity system in New York State. In broad terms, the advanced energy community supports the overall recommendations and

[23] https://noharm-uscanada.org/articles/news/us-canada/lancet-releases-major-health-and-climate-change-report

direction of BCA White Paper, but we have also included in these comments some significant sources of disagreement and find that the proposed Framework falls short in some key areas. We recognize the complexity of what is being undertaken and look forward to our continued involvement in this proceeding and working with all parties to develop a suitable BCA Framework that will help realize the full potential of REV.

Additional References

Below are some additional references for consideration by the Commission. This list is not intended to be exhaustive.

Arrow (1996) *The Role of Benefit-cost analysis in Environmental Health, and Safety Regulation*, http://down.cenet.org.cn/upfile/13/20051271682167.pdf

Matthews (2000) *Applications of Environmental Valuation for Determining Externality Costs*, http://pubs.acs.org/doi/abs/10.1021/es9907313

Muller (2011), *Linking Policy to statistical uncertainty in air pollution damages*, (http://www.degruyter.com/view/j/bejeap.2011.11.issue-1/bejeap.2011.11.1.2925/bejeap.2011.11.1.2925.xml)

A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, Interstate Renewable Energy Council, Inc., October 2013. (http://www.irecusa.org/2013/10/experts-propose-standard-valuation-method-to-determine-benefits-and-costs-of-distributed-solar-generation/)

Attachment A:

***Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits*, Synapse Energy Economics, September 22, 2014.**

BENEFIT-COST ANALYSIS FOR DISTRIBUTED ENERGY RESOURCES

A Framework for Accounting for All Relevant Costs and Benefits

Prepared for the Advanced Energy Economy Institute

September 22, 2014

AUTHORS

Tim Woolf
Melissa Whited
Erin Malone
Tommy Vitolo, PhD
Rick Hornby

AEE INSTITUTE

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

About the Advanced Energy Economy Institute

The Advanced Energy Economy Institute (AEEI) is a 501 (c)(3) charitable organization whose mission is to raise awareness of the public benefits and opportunities of advanced energy. AEEI provides critical data to drive the policy discussion on key issues through commissioned research and reports, data aggregation and analytic tools. AEEI also provides a forum where leaders can address energy challenges and opportunities facing the United States.

AEEI is affiliated with Advanced Energy Economy (AEE), a 501(c)(6) business association, whose purpose is to advance and promote the common business interests of its members and the advanced energy industry as a whole. AEE and AEEI work cooperatively with a national coalition of allied state and regional organizations to promote the public benefits of the advanced energy economy throughout the country. The AEE State Coalition currently includes 15 partner organizations covering 23 states.

Since March 2013, AEEI, working in partnership with MIT's Industrial Performance Center, has organized a series of CEO Forums that are helping to define needed changes in business and regulatory models to accelerate the growth of advanced energy in the power sector. Participants in the 21st Century Electricity System CEO Forum series include senior executives from utilities and advanced energy companies, regulators and policymakers. AEEI will continue to hold CEO Forums in locations across the country to facilitate stakeholder engagement with the issues associated with development of an electricity system for the 21st century.

AEEI is now actively involved in the New York Public Service Commission's Reforming the Energy Vision (REV) and Clean Energy Fund proceedings, along with its partners Alliance for Clean Energy (ACE NY) and the New England Clean Energy Council (NECEC). This report addresses one of the central issues identified in REV, the need to create a comprehensive benefit-cost analysis framework to assess distributed energy resources. Such a framework is vital to efforts to adapt utility and regulatory models not only in New York but around the country.

AEEI would like to thank the Rockefeller Brothers Fund and the Energy Foundation for their generous support of this Synapse Energy Economics report.

CONTENTS

1. EXECUTIVE SUMMARY 1

2. DER BENEFIT-COST ANALYSIS FRAMEWORK 8
   - 2.1. Summary and Recommendations 8
   - 2.2. Background 9
   - 2.3. Staff's Straw Proposal for DER Benefit-Cost Analysis 12
   - 2.4. The Societal Cost Test 12
   - 2.5. The Utility Cost Test 14
   - 2.6. The Rate Impact Measure Test 15

3. IMPACTS OF DISTRIBUTED ENERGY RESOURCES 19
   - 3.1. Relevant Parties and Perspectives of Interest 19
   - 3.2. Universe of Costs and Benefits 19
   - 3.3. Impacts on All Utility Customers 20
   - 3.4. Participant Impacts of DERs 30
   - 3.5. Societal Impacts of DERs 33

4. ALTERNATIVE APPROACHES TO ACCOUNT FOR DER IMPACTS 36
   - 4.1. Proxy Values 37
   - 4.2. Alternative Benchmarks 41
   - 4.3. Regulatory Judgment 42
   - 4.4. Multi-Attribute Decision Analysis 43
   - 4.5. Summary 44

5. ACCOUNTING FOR RISK IN THE BCA FRAMEWORK 47
   - 5.1. Summary 47
   - 5.2. Background on Risk 48
   - 5.3. Accounting for Risk in DER Benefit-Cost Analyses 49

6. DISCOUNT RATES 54

6.1. Summary and Recommendations 54
6.2. Background on Discount Rates 55
6.3. Discount Rates for DER Benefit-Cost Analyses 58
6.4. Recommendations 61

7. Example Templates 63
7.1. Screening Template 63
7.2. Multi-Attribute Decision Analysis Template 64

Works Cited 65

Appendix A: Glossary and Acronyms 69

Appendix B: Quantification and Monetization of DER Impacts 73
Accounting for Benefits to All Utility Customers 73
Accounting for Costs to All Utility Customers 78
Accounting for Benefits to Participants 80
Accounting for Costs to Participants 82
Accounting for Benefits to Society 83
Accounting for Costs to Society 84

1. EXECUTIVE SUMMARY

Introduction

In its proceeding on Reforming the Energy Vision, the New York Public Service Commission has undertaken a comprehensive, ambitious, and forward-thinking initiative to improve the efficiency of the New York electricity system through the promotion of distributed energy resources (DERs). This initiative should be supported with a similarly comprehensive, ambitious, and forward-thinking benefit-cost analysis that will provide the Commission and other stakeholders with the information necessary to determine which resources will be in the public interest and will meet the Commission's energy policy goals.

The benefit-cost analysis techniques that have been used for many years for evaluating energy efficiency resources are undergoing change. Several states, including New York, have been wrestling with how to improve their efficiency screening practices to better meet their needs. The key concerns with the current screening practices are that (a) the standard cost-effectiveness tests are seen as too narrowly defined; (b) some of the hard-to-quantify costs and benefits are ignored in practice; and (c) the standard cost-effectiveness tests do not necessarily account for the benefits articulated in state energy policy goals.

The discussion and recommendations in this document are based on the fundamental premise that in order to meet the Commission's policy goals, all components of the DER benefit-cost analysis framework must be designed in a way that is consistent with those goals.

Over the past year, energy efficiency experts have been working to improve the efficiency screening practices in several states through the National Efficiency Screening Project. That effort has led to a set of recommendations for moving beyond the standard efficiency screening tests by adhering to important principles. Several of these key principles and recommendations are incorporated into this report in order to address the challenges identified by historical screening practices.

One important theme runs throughout this document and our recommendations. The Commission has been explicit about achieving certain policy goals through the implementation of distributed energy resources. In addition to the standard regulatory goals of providing low-cost, reliable, safe electricity service at just and reasonable rates, the Commission identified the following policy goals: enhanced customer empowerment, market animation, system-wide efficiency, fuel and resource diversity, system reliability and resiliency, and reduction of carbon emissions. The discussion and recommendations in this document are based on the fundamental premise that in order to meet these goals, all components of the DER benefit-cost analysis (BCA) framework must be designed in a way that is consistent with these goals.

The Societal Cost Test

The DER benefit-cost analysis framework that we propose in this report builds on the experience and lessons learned from energy efficiency screening in New York and elsewhere. The state has historically relied upon the Total Resource Cost (TRC) Test in evaluating the cost-effectiveness of energy efficiency. However, in recent years, the Commission, Staff, and other stakeholders have expressed concerns that the TRC test is too narrowly-defined and does not account for a sufficient range of benefits, particularly non-energy benefits, hard-to-quantify benefits, and specific benefits articulated in New York's energy policy goals.

In its August 22 REV Track One Straw Proposal, Staff is clear that the benefit-cost analysis (BCA) framework should be used to "meet overall system cost efficiency, reliability, resiliency, security and societal goals" (NY DPS Staff 2014a, 44). This language suggests a preference for using the Societal Cost Test for the DER BCA framework. Staff also proposes that the results of the Societal Cost Test, Utility Cost Test, and Rate Impact Measure test be reported when evaluating DERs (NY DPS Staff 2014a, 44). This language indicates the importance of considering utility system impacts and customer rate impacts when assessing resource cost-effectiveness.

Based on this background, we recommend that the Societal Cost Test be used as the primary basis for deciding whether to proceed with any particular DER program or portfolio. However, the Societal Cost Test must be designed and applied in a way that ensures that all of New York's energy policy goals are accounted for, particularly those articulated by the Commission in the REV docket. This requires including some benefits that are not typically included in the Societal Cost Test, for example, customer empowerment and DER market animation.

We recommend that the Societal Cost Test be used as the primary basis for deciding whether to proceed with any particular DER program or portfolio. However, it must be designed and applied in a way that ensures that all of New York's energy policy goals are accounted for.

In addition, we support Staff's proposal that the Utility Cost Test results be reported as part of the DER BCA framework. However, these results should not be used in isolation for deciding whether to proceed with any particular DER program or portfolio. Instead, they should primarily be used to inform the analyses of rate, bill, and participant impacts.

Rate, Bill, and Participation Impacts

Impacts on electricity rates should be an important consideration as the Commission proceeds with its REV proposals. However, the Rate Impact Measure (RIM) test should not be used for assessing the rate impacts of DER because it suffers from several fundamental flaws. For example:

- The RIM test does not provide the specific information that utilities and regulators need to assess the actual rate and equity impacts of distributed energy resources.
- The RIM test will not result in the lowest cost to customers. Minimizing utility system costs and average customer bills should be given priority over minimizing rates.
- A strict application of the RIM test often results in perverse outcomes, where significant reductions in utility system costs are rejected in order to avoid what may be insignificant impacts on customers' rates.

- The lost revenues that are included in the RIM test[1] are not a *new cost* created by deployment of DERs; they are caused by the need to recover *existing* costs spread out over fewer sales. Sunk costs should not be used to assess future resource investments, because they are incurred regardless of whether the future project is undertaken.

These problems with the RIM Test do not mean that rate impacts of DERs should be ignored. Instead, a better approach should be used to provide the information necessary to understand potential rate impacts and potential customer equity concerns. A thorough understanding of the implications of DER rate impacts requires comprehensive analysis of three important factors:

The RIM test does not provide the specific information that utilities and regulators need to assess the actual rate and equity impacts of distributed energy resources.

- Rate impacts, to provide an indication of the extent to which rates for all customers might increase due to distributed energy resources.
- Bill impacts, to provide an indication of the extent to which customer bills might be reduced for those customers that install distributed energy resources.
- Participation impacts, to provide an indication of the portion of customers that will experience bill reductions or bill increases. Participating customers will generally experience bill reductions, while non-participants might see rate increases leading to bill increases.

Taken together, these three factors indicate the extent to which customers as a whole will benefit from distributed energy resources, and the extent to which distributed energy resources might create distributional equity concerns.

The Universe of Distributed Energy Resources Impacts

To encourage investments that will achieve New York's energy policy goals, all costs and benefits that impact those goals should be taken into account. Table 1 below provides an overview of the universe of costs and benefits that may be attributed to DERs, grouped by the party experiencing the impact: all customers, participants, and society as a whole.

[1] Inclusion of lost revenues is the only difference between the RIM Test and the Utility Cost Test.

Table 1. Universe of Relevant Distributed Energy Resource Impacts

	BENEFITS			COSTS		
		Category	Examples		Category	Examples
Impacts on All Customers	1	**Load Reduction & Avoided Energy Costs**	Avoided energy generation and line losses, price suppression	1	**Program Administration Costs**	Program marketing, administration, evaluation; incentives to customers
	2	**Demand Reduction & Avoided Capacity Costs**	Avoided transmission, distribution, and generation capacity costs, price suppression	2	**Utility System Costs**	Integration capital costs, increased ancillary services costs
	3	**Avoided Compliance Costs**	Avoided renewable energy compliance costs, avoided power plant retrofits	3	**DSP Costs**	Transactional platform costs
	4	**Ancillary Services**	Regulation, reserves, energy imbalance			
	5	**Utility Operations**	Reduced financial and accounting costs, lower customer service costs			
	6	**Market Efficiency**	Reduction in market power, market animation, customer empowerment			
	7	**Risk**	Project risk, portfolio risk, and resliency			
Participant Impacts	1	**Participant Non-Energy Benefits**	Health and safety, comfort, tax credits	1	**Participant Direct Costs**	Contribution to measure cost, transaction costs, O&M costs
	2	**Participant Resource Benefits**	Water, sewer, and other fuels savings	2	**Other Participant Impacts**	Increased heating or cooling costs, value of lost service, decreased comfort
Societal Impacts	1	**Public Benefits**	Economic development, reduced tax burden	1	**Public Costs**	Tax credits
	2	**Environmental Benefits**	Avoided air emissions and reduced impacts on other natural resources	2	**Environmental Costs**	Emissions and other environmental impacts

Approaches to Account for DER Impacts

Direct monetization is the preferred approach to valuing impacts, and should be chosen whenever possible. However, if a cost or benefit cannot be readily monetized, it should be accounted for in another manner, whether through proxies, alternative benchmarks, regulatory judgment, or multi-attribute decision analysis, as described below.

- Proxies: Proxies generally represent the next best valuation option, after direct monetization. Proxies are an explicit recognition that a particular impact should not be ignored and should be approximated using the best information available. Proxies can be applied in several forms, including as a multiplier applied to avoided costs, a multiplier applied to electricity saved or generated; or a multiplier applied to the number of participating customers. Proxies can also be applied at different levels of granularity, e.g., portfolio level, resource level, sector level, program level, or impact level.
- Alternative screening benchmarks: In the absence of monetary values or proxies, relevant benefits can be accounted for using alternative screening benchmarks. This approach allows DER programs to be considered cost-effective at pre-determined benefit-cost ratios that are less (or greater) than one. Alternative benchmarks eliminate the need for identifying values for DER

impacts by category, or by program. It is, by design, a simplistic way of recognizing that the combination of DER impacts for any one program is significant enough to influence the cost-effectiveness analysis. Regulators can choose an alternative benchmark that they are comfortable with by program, by sector, by resource type, or for a DER portfolio.

- Regulatory judgment: Accounting for DER impacts through regulatory judgment allows regulators to make a determination that a resource is cost-effective without monetizing every impact and without applying an alternative screening benchmark. This approach allows regulators to make the cost-effectiveness determination in consideration of the specific DER being analyzed, the specific monetized impacts of that DER, and the specific non-monetized impacts of that DER. Regulatory judgment should always be made with the greatest amount of information available, including qualitative and quantitative information on impacts that have not been monetized.

- Multi-attribute decision analysis (MADA): Multi-attribute decision analysis is a systematic process for weighting and scoring both monetized and non-monetized criteria in order to rank several options across all the criteria. To compare alternatives, MADA utilizes a decision matrix that summarizes the data available regarding each alternative's attributes, and weights each attribute according to its importance. This approach requires some amount of regulatory judgment in terms of setting weights across the different criteria, but that judgment is transparent in the MADA framework and can be informed by stakeholder input. Multi-attribute decision analyses must be designed and conducted very carefully to avoid inappropriate manipulation or unintended consequences.

Table 2 presents an illustration of what might be the preferred valuation option for each type of DER benefit: monetization, proxy, or MADA. A similar table for costs is presented in Chapter 4. A "yes" indicates which valuation option is likely to be the preferred method of accounting for the specific benefit, based on our initial assessment. This information is intended to illustrate how a mix of valuation options could be used. The actual valuation methods should be determined through more analysis specific to the New York DER BCA framework. In addition, the best valuation method can be expected to change over time as more data become available.

Table 2. Illustrative Options for Valuing DER Benefits

Party Impacted	Benefits		Valuation Method		
	Benefit Category		Monetization	Proxy	Multi-Attribute
Utility Customers	1	Load Reduction & Avoided Energy Costs	yes	---	---
	2	Demand Reduction & Avoided Capacity Costs	yes	---	---
	3	Avoided Compliance Costs	yes	---	---
	4	Avoided Ancillary Services	yes	---	---
	5	Utility Operations	yes	---	---
	6	Market Efficiency	---	---	yes
	7	Risk	---	yes	---
Participants	8	Participant Non-Energy Benefits	---	yes	---
	9	Participant Resource Benefits	yes	---	---
Society	10	Public Benefits	yes	---	yes
	11	Environmental Benefits	yes	---	yes

Methods to Account for Risk

The purpose of the DER BCA framework is to identify those distributed energy resources that will meet a set of regulatory goals. Those goals include reducing electricity costs, increasing electricity system efficiency, maintaining reliability, reducing risk, and achieving other energy policy goals, both in the short-term and the long-term future. The BCA framework should account for risk in a way that is consistent with those goals. For example, if the state's energy policy goals place a high value on avoiding the risks associated with volatile fossil fuel prices, then those risks should receive commensurate priority in the benefit-cost analysis.

Distributed energy resources generally result in reduced risk to the electricity system, relative to traditional supply-side resources. DERs can increase the diversity of the portfolio of electricity resources, reduce reliance upon fossil fuels with volatile prices, reduce planning risk by reducing load growth, reduce risks associated with current and future environmental regulations, and reduce risks associated with outages caused be storms and other unexpected events. Distributed energy resources also help to reduce risk through increased optionality and system resiliency. That is, through their distributed and small-scale nature, DER investments offer greater flexibility in helping the system cope with stress and respond to unanticipated changes in the future (relative to large, capital-intensive generation, transmission or distribution upgrades).

Risk can be accounted for in the DER BCA framework using a variety of techniques, including: sensitivity analyses, scenario analyses, probability analyses, risk proxies, and the choice of discount rate. Accounting for risk through the choice of discount rate requires considering risk as one of several factors that might influence the choice of discount rate.

Some of the risk assessment techniques listed above can be used in combination. Either way, risk should be accounted for in the BCA framework in a way that is transparent, does not understate risk impacts, and does not double-count or overstate risk impacts.

The questions of which risk assessment techniques should be used in the DER BCA framework—and how—should be addressed once the BCA framework is more fully developed, when the risk analyses can be applied to specific types of costs and benefits. The key points to make at this time are:

- The risk impacts of DERs should not be ignored because they are difficult to assess;
- There are a variety of techniques that can be used for risk assessment; and
- Accounting for risk impacts can be interrelated with the choice of discount rates.

The societal discount rate is best able to reflect the value of short- versus long-term costs and benefits to all utility customers, as well as to society in general.

The Societal Discount Rate

The choice of a discount rate for the DER BCA framework is not a simple, formulaic decision. The choice of discount rate is essentially a decision about time preference; in other words, the relative importance of short- versus long-term costs and benefits.

New York utilities currently use a discount rate based upon a utility's weighted average cost of capital when evaluating the cost-effectiveness of energy efficiency resources. This is a relatively high discount rate, and therefore places relatively less value on the long-term benefits of energy efficiency resources. We recommend that this practice not be used as a precedent for the discount rate in the DER BCA framework, for reasons discussed below.

The time preference used by a regulated utility for evaluating the costs and benefits of resource options can be very different from the time preference used by investors for evaluating their investment options. Regulated utilities have a variety of different goals and responsibilities to consider when planning their system (e.g., reducing system costs, increasing system efficiency, maintaining reliability, maintaining customer equity, maximizing profits for shareholders, mitigating risks to customers, and achieving other energy policy goals as required by the state). Individual investors have a different set of goals when making financial decisions (e.g., balancing risks and rewards, maximizing profits, maximizing short-term versus long-term returns). Consequently, the utility investors' time preference, as indicated by the utility weighted average cost of capital, is not necessarily appropriate for setting the discount rate for the DER BCA framework.

The purpose of the DER BCA framework is to identify those distributed energy resources that will meet a set of regulatory goals, including: reduce electricity costs, increase electricity system efficiency, maintain reliability, reduce risk, and achieve the other energy policy goals, both in the short-term and the long-term future. The discount rate chosen for the DER BCA framework must reflect a time preference that is consistent with this set of regulatory goals. The time preference indicated by the utility weighted average cost of capital is not consistent with this set of regulatory goals, and therefore will not lead to resource decisions that are consistent with this set of goals.

We recommend that the DER BCA framework use a societal discount rate. The societal discount rate is best able to reflect the value of short- versus long-term costs and benefits to all utility customers, as well as to society in general. The societal discount rate is best able to reflect the time preference associated with the state's energy policy goals, many of which are related to societal impacts. In addition, the societal discount rate is consistent with the use of the Societal Cost Test, which we recommend for screening distributed energy resources.

We also recommend that the societal discount rate chosen for the DER BCA framework be somewhere in the range of 0 to 3 percent real. This range is frequently used for societal discount rates, and is also very close to the current value of risk-free discount rates.

Additional factors, particularly risk, should be considered in choosing, within this range, the exact discount rate for the DER BCA framework. To the extent that risk has been evaluated and accounted for through other methods described in Chapter 5, then the Commission should choose a discount rate at the high end of the range of societal discount rates. If risk has not been adequately evaluated and accounted for through other methods, then the Commission should choose a discount rate at the low end of that range.

2. DER Benefit-Cost Analysis Framework

2.1. Summary and Recommendations

The DER benefit-cost analysis framework that we propose in this report builds on the experience and lessons learned from energy efficiency screening in New York and elsewhere. The state has historically relied upon the Total Resource Cost (TRC) Test in evaluating the cost-effectiveness of energy efficiency. However, in recent years the Commission, Staff, and other stakeholders have expressed concerns that the TRC test is too narrowly defined and does not account for a sufficient range of benefits, particularly non-energy benefits, hard-to-quantify benefits, and benefits associated with New York's energy policy goals.

In its August 22, 2014, REV Track One Straw Proposal, Staff is clear that the benefit-cost analysis (BCA) framework should be used to "meet overall system cost efficiency, reliability, resiliency, security and societal goals" (NY DPS Staff 2014a, 44). This language suggests a preference for using the Societal Cost Test for the DER BCA framework. Staff also proposes that the results of the Societal Cost Test, Utility Cost Test, and Rate Impact Measure test be reported when evaluating distributed energy resources (NY DPS Staff 2014a, 44). This language indicates that other factors should be considered in assessing cost-effectiveness, particularly utility system impacts and customer rate impacts.

Over the past year, many efficiency experts have been working to improve the efficiency screening practices in many states through the National Efficiency Screening Project. That effort has led to a set of recommendations for moving beyond the standard efficiency screening tests by adhering to several important principles. Two of the key principles applicable to the New York REV are: (1) ensure that energy policy goals are properly accounted for in the efficiency screening tests, and (2) account for all relevant costs and benefits, even those that are difficult to quantify or monetize.

Based upon this background, we offer the following recommendations for the New York DER BCA framework.

1. The Societal Cost Test should be used as the primary basis for deciding whether to proceed with any particular DER program or portfolio. However, the Societal Cost Test must be designed and applied in a way that ensures that all of New York's energy policy goals are accounted for, particularly those articulated by the Commission in the REV docket. That is, the test must include all costs and benefits that measure the degree to which these energy policy goals are met through a particular resource portfolio.

2. The Utility Cost Test results should be reported as part of the DER BCA framework. However, these results should not be used in isolation for deciding whether to proceed with any particular DER program or portfolio. Instead, they should primarily be used to inform the analyses of rate, bill, and participant impacts.

3. The Rate Impact Measure Test should not be reported or used as part of the DER BCA framework. The Rate Impact Measure test results are not useful for understanding rate impacts,

and are potentially misleading. Rate impact and distributional equity issues should be accounted for through separate, comprehensive analyses of rate, bill, and participant impacts.

The remainder of this chapter describes these recommendations more fully. Chapter 3 describes the universe of costs and benefits that should be accounted for in the New York DER BCA framework. Chapter 4 provides a set of options and analytical tools for accounting for the hard-to-quantify, non-monetized impacts of DERs. Chapter 5 presents recommendations to account for risk, and Chapter 6 presents some recommendations for choosing an appropriate discount rate for the BCA framework. Finally, Chapter 7 pulls many of the concepts from the previous chapters together in sample templates to use in evaluating the costs and benefits of various resource options.

2.2. Background

Standard Energy Efficiency Screening Tests

Five standard cost-effectiveness tests have been developed to consider energy efficiency costs and benefits from different perspectives. Each of these tests combines the various costs and benefits of energy efficiency programs in different ways, depending upon whose perspective is of interest. These tests are summarized in Table 3.

The standard tests presented in Table 3 are originally based on the California Standard Practice Manual (CPUC 2001). Note that these tests are sometimes defined slightly differently in different states, and that some parties disagree with exactly which costs and benefits should be included in each test.

Table 3. Components of the Standard Energy Efficiency Cost Tests

	Participant Test	RIM Test	Utility Test	TRC Test	Societal Test
Energy Efficiency Program Benefits:					
Customer Bill Savings	Yes	---	---	---	---
Avoided Energy Costs	---	Yes	Yes	Yes	Yes
Avoided Capacity Costs	---	Yes	Yes	Yes	Yes
Avoided Transmission and Distribution Costs	---	Yes	Yes	Yes	Yes
Wholesale Market Price Suppression Effects	---	Yes	Yes	Yes	Yes
Avoided Cost of Environmental Compliance	---	Yes	Yes	Yes	Yes
Non-Energy Benefits (utility perspective)	---	Yes	Yes	Yes	Yes
Non-Energy Benefits (participant perspective)	Yes	---	---	Yes	Yes
Non-Energy Benefits (societal perspective)	---	---	---	---	Yes
Energy Efficiency Program Costs:					
Program Administrator Costs	---	Yes	Yes	Yes	Yes
EE Measure Cost: Program Financial Incentive	---	Yes	Yes	Yes	Yes
EE Measure Cost: Participant Contribution	Yes	---	---	Yes	Yes
Non-Energy Costs (utility, participant, societal)	---	Yes	Yes	Yes	Yes
Lost Revenues to the Utility	---	Yes	---	---	---

Each screening test provides different information to be used for different purposes. Table 4 summarizes the implications of each test: the key question answered, the costs and benefits included, and what the results of the test indicate. The Societal Cost Test is the most comprehensive and is best able to account for all energy policy goals. We return to this test in more detail in Section 2.4.

Table 4. Implications of the Standard Energy Efficiency Cost-Effectiveness Tests

Test	Key Question Answered	Costs and Benefits Included	Implications
Societal Cost Test	Will there be a net reduction in societal costs?	Costs and benefits experienced by all members of society.	Most comprehensive. Best able to account for all energy policy goals.
Total Resource Cost Test	Will there be a net reduction in costs to all customers?	Costs and benefits experienced by all utility customers, including program participants and non-participants.	Indicates the full incremental costs of the resource. Generally includes full societal costs but not full societal benefits.
Utility Cost Test	Will there be a net reduction in utility system costs?	Costs and benefits to the utility system as a whole, including generation, transmission, and distribution impacts.	Indicates the impact on average customer bills.
Participant Cost Test	Will there be a net reduction in program participant costs?	Costs and benefits experienced by the customer who participates in the program.	Of limited use for cost-effectiveness screening. Useful in program design to understand and improve participation.
Rate Impact Measure	Will there be a net reduction in utility rates?	Costs and benefits that will affect utility rates, including utility system impacts plus lost revenues.	Should not be used for cost-effectiveness screening. Does not provide useful information regarding rate impacts or customer equity impacts.

Limitations of the Total Resource Cost Test as Currently Used

New York has historically relied upon the Total Resource Cost (TRC) Test in evaluating the cost-effectiveness of energy efficiency, but the benefits and costs included in this test have changed over time (NY DPS Staff 2007). In 2008, the Commission required that non-energy benefits,[2] among other factors, should be fully described to the extent that they are applicable to a specific energy efficiency project. These non-energy benefits were defined as "including benefits other than direct cost savings and demand reduction/system benefits, e.g. employment opportunities, effect on low-income customers, effect on housing stock, environmental justice implications, or environmental benefits other than those generally attributable to energy efficiency improvements" (NY PSC 2008, App. 3).

Since 2008, Staff and stakeholders have repeatedly expressed concerns regarding how the TRC Test is applied. In 2011, Staff issued a white paper that highlighted the failure of the TRC Test to capture non-energy impacts, leading to understated benefit-cost ratios. The white paper also discussed hard-to-quantify benefits that include many factors underlying the Commission's policy on renewable energy, including reducing the state's vulnerability to fuel shortages, job creation, improving energy price stability, and reducing air emissions and other environmental damages (NY DPS Staff 2011).

[2] The Commission's Order used the term "co-benefits." In this report, the term co-benefits is considered synonymous with non-energy benefits.

Many parties supported Staff's comments and argued that the cost-effectiveness test is too narrowly defined and should account for a wider range of benefits. One of the primary benefits historically omitted from the test is the reduced risk associated with energy efficiency investments. This omission has continued despite the Commission's lengthy discussion in its 2011 Order of reduced risk of supply disruptions or gas price jumps as a major reason to continue energy efficiency programs in the face of current low natural gas prices (NY PSC 2011).

In the current REV proceeding, cost-effectiveness is again being examined in New York. A primary emphasis of the proceeding is on accounting for the full range of impacts of DER in a manner that goes beyond the limited application of the TRC Test.

A New Development in Resource Screening Practices: The Resource Value Framework

In recent years, many states have wrestled with similar issues regarding their energy efficiency screening processes. Consequently, the Resource Value Framework was developed to help states identify screening practices tailored to their unique needs and interests (NESP 2014).[3] The Resource Value Framework starts from the premise that the standard cost-effectiveness tests defined in the California Standard Practice Manual, particularly the Ratepayer Impact Measure (RIM), the Utility Cost Test and the TRC Test, are not sufficient to address some of the key issues of concern to regulators. State screening processes should go beyond these tests, rather than be limited by the tests' narrow definitions.

The Resource Value Framework is not a recommendation for a single cost-effectiveness test. Instead, it is a framework of principles and recommendations to guide states in developing and implementing tests that are consistent with best practices and address the goals of their particular state. The framework is based upon the following principles:

- The Public Interest. The ultimate objective of screening is to determine whether a particular resource is in the public interest.
- Energy Policy Goals. Screening practices should account for the energy policy goals of each state, as articulated in legislation, commission orders, regulations, guidelines, and other policy directives. These policy goals provide guidance with regard to which costs and benefits should be accounted for when determining whether investments are in the public interest.
- Symmetry**.** Screening practices should ensure that tests are applied symmetrically, where both relevant costs and relevant benefits are included in the screening analysis.
- Hard-to-Quantify Benefits. Screening practices should not exclude relevant benefits on the grounds that they are difficult to quantify and monetize. Several methods are available to approximate the magnitude of relevant benefits, as described later in this report.

[3] The Resource Value Framework was developed by the National Efficiency Screening Project, which is composed of over 30 efficiency, environmental, and other member organizations, and is guided by a team of project advisors that includes 16 efficiency experts from the United States and Canada. See NESP 2014 for more details. Synapse Energy Economics is the lead technical consultant for the National Efficiency Screening Project.

- Transparency. A standard template should be used to explicitly identify state energy policy goals and to document assumptions and methodologies.

Many of the principles and recommendations articulated in the Resource Value Framework are relevant to developing a benefit-cost analysis framework for distributed energy resources in New York.

2.3. Staff's Straw Proposal for DER Benefit-Cost Analysis

In its August 22, 2014, REV Track One Straw Proposal, Staff provided recommendations for how a benefit-cost analysis framework could be applied in the context of developing the REV market in New York. Staff expects BCA to be used for three different purposes: (1) utility distributed system platform (DSP) implementation plans; (2) periodic utility resource plans; and (3) pricing and procurement of distributed energy resources (NY DPS Staff 2014a).

The Staff Straw Proposal is clear that the BCA should account for societal and energy policy goals, stating that the "primary application of the BCA framework, though, is expected to be used by utilities in planning their distribution systems, including DSP investments and DER, to meet overall system efficiency, reliability, resiliency, security, and societal goals" (NY DPS Staff 2014a, 44). Staff is also clear that the BCA framework should account for hard-to-quantify benefits (NY DPS Staff 2014a, 49).

The Staff Straw Proposal recommends that BCA results should be reported using the Societal Cost Test, the Utility Cost Test, and the Rate Impact Measure test. Recognizing the complexities and outstanding issues regarding the BCA framework for DER, Staff proposes that a stakeholder process be used to design the BCA framework (NY DPS Staff 2014a).

2.4. The Societal Cost Test

Among all the tests typically used for screening energy efficiency resources, and all the tests proposed by the Staff in its Straw Proposal, the Societal Cost Test will provide the most information regarding the costs and benefits of importance to the Commission. The Societal Cost Test is the most comprehensive of the screening tests, and provides the most information about the impacts of distributed energy resources.

However, in developing the DER BCA framework for New York, care must be given to ensure that the Societal Cost Test accounts for the energy policy goals of the Commission. All energy policy goals should be accounted for somehow, even if some of them are difficult to quantify or monetize.

State energy policy goals can be articulated in several different ways, including legislation, regulations, commission guidelines, commission standards, commission orders, and other pronouncements from a commission or a relevant state agency. These can all provide guidance on the energy policy goals to account for in a BCA framework.

For example, New York statutes state that it shall be the energy policy of the state:

- "to obtain and maintain an adequate and continuous supply of safe, dependable and economical energy for the people of the state and to accelerate development and use within the state of renewable energy sources, all in order to promote the state's economic growth, to create employment within the state, to protect its environmental values and agricultural heritage, to husband its resources for future generations, and to promote the health and welfare of its people;
- to encourage conservation of energy in the construction and operation of new commercial, industrial, agricultural and residential buildings, and in the rehabilitation of existing structures, through heating, cooling, ventilation, lighting, insulation and design techniques and the use of energy audits and life-cycle costing analysis;
- to encourage the use of performance standards in all energy-using appliances, and in industrial, agricultural and commercial applications of energy-using apparatus and processes;
- to encourage transportation modes and equipment which conserve the use of energy;
- to foster, encourage and promote the prudent development and wise use of all indigenous state energy resources including, but not limited to, on-shore oil and natural gas, off-shore oil and natural gas, natural gas from Devonian shale formations, small head hydro, wood, solar, wind, solid waste, energy from biomass, fuel cells and cogeneration; and
- to encourage a new ethic among its citizens to conserve rather than waste precious fuels; and to foster public and private initiative to achieve these ends at the state and local levels." (Laws of New York)

As another example, the Department of Public Service mission statement identifies the goals of ensuring "affordable, safe, secure, and reliable access to electric, gas, steam, telecommunications, and water services … while protecting the natural environment. The Department also seeks to stimulate effective competitive markets that benefit New York consumers through strategic investments, as well as product and service innovations" (NY DPS 2014).

When the Commission established the energy efficiency System Benefit Charge 15 years ago, it "recognized that along with research and development and support for low-income customers, energy efficiency and environmental protections are important elements of a comprehensive energy policy" (NY PSC 2013, 2).

In more recent years, the Commission elaborated upon its energy efficiency policy goals:

> The Commission's policy is to stimulate the increased availability of energy efficiency measures throughout the State, and to make these measures a permanent feature of the energy industries. This policy should diversify our energy resources, improve energy security, enhance system reliability, attract energy efficiency providers to New York, improve the State and global environment by reducing air emissions, and develop an EEPS that is cost effective and subject to regular and verifiable evaluation. (NY PSC 2008, 68)

Further, the Commission has clearly articulated several energy policy objectives that it specifically wishes to achieve from the promotion of distributed energy resources in the context of REV. These include: (a) enhanced customer knowledge and tools that will support effective management of their total energy bill; (b) market animation and leverage of ratepayer contributions; (c) system-wide efficiency; (d) fuel and resource diversity; (e) system reliability and resiliency; and (f) reduction of carbon emissions (NY DPS Staff 2014b, 2).

If distributed energy resources are to meet these energy policy goals, then it will be important to ensure that benefits and costs measuring progress toward all of these goals are somehow incorporated into the Societal Cost Test used in New York. Methods for accounting for hard-to-quantify impacts relevant to energy policy goals are discussed in Chapter 4 below.

2.5. The Utility Cost Test

The Utility Cost Test (UCT) provides some very useful information regarding the costs and benefits of distributed energy resources. In theory, the UCT should include all the costs and benefits to the utility system over the long term.[4] Therefore, the UCT provides a good indication of the extent to which utility system costs, and therefore average customer bills, are likely to be reduced as a result of distributed energy resource investments.

However, the Utility Cost Test by itself does not provide sufficient information for the BCA framework for distributed energy resources in New York. A strict application of the Utility Cost Test does not allow for consideration of some key energy policy goals, e.g., reduced environmental and health impacts, and increased economic development. In addition, a strict application of the Utility Cost Test does not allow for consideration of the specific costs and benefits that accrue to the DER participants, e.g., low-income benefits, participant non-energy benefits, and non-electric fuel savings.

Further, conventional application of the Utility Cost Test does not allow for consideration of some of the key energy policy goals that *are* related to the utility system, but are not typically accounted for in the Utility Cost Test because they are difficult to quantify. This would include, for example, improved reliability, reduced risk, customer empowerment, and promotion of the retail market for DER products and services.

In sum, it is appropriate to report the results of the Utility Cost Test, because it provides useful information regarding the reduction in electricity system costs and average customer bills. However, the Utility Cost Test results should not be used as the primary basis for deciding whether to proceed with any particular DER program or portfolio, because they do not include the impacts associated with key energy policy goals. The Societal Cost Test is much better suited for that purpose. Finally, the results of the Utility Cost Test should be used to provide useful information in the separate analysis of rate, bill, and participation impacts.

[4] In a state with retail competition for generation services, such as New York, the "utility system" includes the revenue requirements of the transmission and distribution utility, as well as the costs and benefits associated with wholesale and, ultimately, retail generation services.

2.6. The Rate Impact Measure Test

In the Straw Proposal, Staff proposed that the RIM test results be presented, along with other test results, as part of the BCA framework. Presumably, Staff recommends reporting the RIM test results in order to provide an indication of how DER will affect electricity customer rates.

Impacts on electricity rates should certainly be considered as the Commission proceeds with its REV proposals. However, the RIM test should not be used for assessing the rate impacts of DER. The RIM test suffers from many fundamental flaws and does not provide the Commission and other stakeholders with information necessary to assess rate impacts or the distributional equity issues that go along with them. Other approaches are much better suited for assessing rate impacts. These points are discussed in more detail below.

Problems with the Rate Impact Measure Test

In general, DER programs can affect rates in several ways, including (a) increasing rates to recover DER administration and implementation costs from all customers; (b) reducing transmission and distribution rates as a result of reduced transmission and distribution costs; (c) reducing generation rates by suppressing wholesale prices in the wholesale electricity markets; and (d) increasing rates to recover "lost revenues" from DERs.[5] In general, the increase in rates needed to recover DER costs from customers is offset by the reduction in rates as a result of avoided costs and the wholesale price suppression effect, particularly over the long term.[6] However, the recovery of lost revenues can lead to a net increase in electricity rates. Hence, understanding the impact of lost revenue recovery is essential to understanding how DERs might affect electricity rates.

The only difference between the RIM test and the Utility Cost Test is the treatment of lost revenues. If the utility is to be made financially neutral to the impacts of the DER programs, then the utility would need to collect the lost revenues associated with the fixed cost portion of current rates. If the utility were to recover these lost revenues over time, then they would create upward pressure on future electricity rates.

One of the problems with the RIM test is that the lost revenues are not a *new* cost created by deployment of DERs. Lost revenues are simply a result of the need to recover *existing* costs spread out over fewer sales. The existing costs that might be recovered through rate increases as a result of lost revenues are (a) not caused by the distributed energy resources themselves, and (b) are not a new, incremental cost. In economic terms, these existing costs are "sunk" costs. Sunk costs should not be

5 The term "lost revenues" is used to describe the effect where DERs reduce electricity sales and prevent the distribution utility from recovering the amount of revenues it would otherwise have recovered.

6 In the absence of lost revenue recovery, any DER program that passes the Utility Cost Test will lead to a net reduction in long-term electricity rates.

used to assess future resource investments because they are incurred regardless of whether the future project is undertaken. Application of the RIM test is a violation of this important economic principle.

The RIM test does not provide the specific information that utilities and regulators need to assess the actual rate and equity impacts of distributed energy resources.

Another problem with the RIM test is that it frequently will not result in the lowest cost to customers. Instead, it may lead to the lowest rates (all else being equal, and if the test is applied properly). However, achieving the lowest rates is not the primary or sole goal of utility planning and regulation; there are many goals that utilities and regulators must balance in planning the electricity system. Maintaining low utility system costs, and therefore low customer bills, should be given priority over minimizing rates. For most customers, the size of the electricity bills that they must pay is more important than the rates underlying those bills.

To emphasize this point, a strict application of the RIM test often results in 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 particular DER program might offer hundreds of millions of dollars in net benefits under the Utility Cost Test (i.e., net reductions in revenue requirements), but be rejected as not cost effective with a RIM test benefit-cost ratio of 0.9. It may well be that the actual rate impact, if calculated properly, is likely to be so small as to be unnoticeable. Rejecting such large reductions in utility system costs to avoid *de minimus* rate impacts is clearly not in the best interests of customers overall, nor is it consistent with New York energy policy goals.

In addition, the RIM test does not provide any information about what actually happens to rates as a result of DER investments. A RIM benefit-cost ratio of less than one indicates that rates will increase (all else being equal), but says little to nothing about the magnitude of the rate impact, 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 utilities and regulators to consider the magnitude and implications of the rate impacts. What are the implications of DER investments with a RIM benefit-cost ratio of 0.98? Or a benefit-cost ratio of 0.87? How much are customers harmed by these results if the Utility Cost Test leads to a benefit-cost ratio of 2.2? The RIM test cannot answer such important questions.

Even worse, the RIM test results can be very misleading. For a DER program with a RIM benefit-cost ratio of less than one, the net benefits (in terms of present value dollars) will be negative. A negative net benefit implies that the distributed energy resource 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 distributed energy resources. They are existing costs, existing fixed costs in particular, that are already in current electricity 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 sometimes present their RIM test results as negative net benefits, implying that the cost impacts of the distributed energy resource investment are worse than they really are (Woolf 2014, 23).

Most importantly, the RIM test does not provide the specific information that utilities and regulators need to assess the actual rate and equity impacts of distributed energy resources. Such information includes the impacts of distributed energy resources on long-term average rates, the impacts on average customer bills, and the extent to which customers participate in DER programs and thereby experience lower bills. The importance of this information is addressed further in the next subsection.

In sum, the RIM test should never be used for the purpose of deciding whether to spend ratepayer money on any particular distributed energy resource. Instead, a different type of analysis should be conducted separately from the BCA to help inform the Commission and others about the potential rate impacts and equity concerns of distributed energy resources.

A Better Approach for Analyzing Rate Impacts and Equity Concerns

Rate impacts from distributed energy resources can raise distributional equity concerns. In general, distributed energy resources can lead to higher rates, but lower average customer bills.[7] Those customers that participate in a DER program, or install distributed energy resources in any way, will typically experience lower bills, while those that do not participate in any way may experience higher rates and therefore higher bills. The different impacts on DER participants and non-participants can create distributional equity concerns.

A thorough understanding of the implications of DER rate impacts requires analysis of three important factors: rate impacts, bill impacts, and participation impacts.

It is important to note that all customers experience some of the benefits of distributed energy resources—regardless of whether they participate in the programs. In particular, distributed energy resources can reduce the need for new generation capacity, reduce wholesale capacity prices, reduce wholesale energy prices, reduce transmission and distribution costs, improve system reliability, reduce risk, and more.[8] All of these benefits accrue to all customers. Nonetheless, it is also generally true that DER participants will experience greater benefits than non-participants, due to the immediate reduction in their electricity bills. This is a key issue to consider when analyzing the implications of rate impacts.

A thorough understanding of the implications of DER rate impacts requires analysis of three important factors: rate impacts, bill impacts, and participation impacts. Rate impacts provide an indication of the extent to which rates for all customers might increase due to distributed energy resources. Bill impacts provide an indication of the extent to which customer bills might be reduced for those customers that install distributed energy resources. Participation impacts provide an indication of the portion of customers will that will experience bill reductions or bill increases; participating customers will generally experience bill reductions while non-participants might see rate increases leading to bill increases. Taken together, these three factors indicate the extent to which customers as a whole will benefit from distributed energy resources, and the extent to which distributed energy resources may lead to distributional equity concerns.

[7] This is not always the case. Many demand response programs can lead to reduced rates, because they involve very little lost revenue recovery. Some energy efficiency programs can lead to reduced rates, depending upon program costs, avoided costs and lost revenue recovery.

[8] Distributed energy resources can also create benefits that are experienced by society in general, such as reduced environmental impacts, economic development, and local job growth.

Care must be given to estimate the rate, bill and participant impacts properly, and to present them in terms that are meaningful for considering distributional equity issues. In particular:

- Rate impact estimates should account for all factors that impact rates. This would include all avoided costs that might exert downward pressure on rates, as well as any factors that might exert upward pressure on rates (primarily, DER program costs and the recovery of lost revenues). Any estimates of the impact of lost revenue recovery on rates should (a) only reflect collection of lost revenues necessary to recover fixed costs, and (b) only reflect the actual impact on rates according the state's ratemaking practices. Rate impacts should be estimated over the long term, to capture the full period of time over which the DER savings will occur. Rate impacts should also be put into terms that place them in a meaningful context; e.g., in terms of ¢/kWh or percent of total rates.
- Bill impact estimates should build upon the estimates of rate impacts. While rate impacts apply to every customer within a rate class, bill impacts will vary between participants and non-participants. As with rate impacts, bill impacts should be estimated over the long term, and they should be put into terms that place them in a meaningful context; e.g., in terms of dollars per month or percent of total bills.
- Participation estimates should be put in terms of participation rates, measured by dividing DER program participants by the total population of eligible customers. This should be done for each year, and should be compared across several years to indicate the extent to which customers are participating in the programs over time. Participation in multiple programs and across multiple years should be captured, and the impacts of participation in multiple DER programs by the same customer should be accounted for to the extent possible.

If this information is not currently available, it should be collected as soon as possible, so that meaningful estimates can be developed in future years. This type of information, particularly the participation rates, will be critical in determining the extent to which distributed energy resources are benefitting customers and achieving New York energy policy goals.

Furthermore, participation information can be used to ensure that most, and potentially all, customers eventually install distributed energy resources of one form or another. The utilities could be charged with the responsibility to identify those customers that do not install distributed energy resources over the medium- to long-term future, and to find ways to reach those customers that have not yet implemented some form of distributed energy resource.

Finally, the rate, bill, and participation impacts for the various types of distributed assets are likely to be considerably different. Therefore, it would be best to estimate impacts for these resource types separately, as well as at the portfolio level.

3. IMPACTS OF DISTRIBUTED ENERGY RESOURCES

3.1. Relevant Parties and Perspectives of Interest

To ensure efficient resource investments, the full range of relevant costs and benefits of distributed energy resources must be accounted for. However, in doing so it is critical to determine which parties are impacted, and in what way, in order to apply cost-effectiveness tests appropriately and to understand the implications for different types of customers.

Three perspectives are generally considered in benefit-cost analysis: (1) all utility customers, (2) participants, and (3) society as a whole. Although utilities and operators of the Distributed System Platform (DSP) will also be impacted by investments in distributed energy resources, these costs and benefits will generally flow back to ratepayers. For this reason, the "all utility customers" perspective is the perspective of interest when examining changes in system costs and benefits.

Each party will experience a different set of costs and benefits stemming from distributed energy resources. Understanding these differential impacts is important for calculating net benefits, as well as for equity considerations. Below we define each party of interest in more detail.

- All utility customers refers to utility ratepayers in general. Distributed energy resources primarily impact all customers by changing utility revenue requirements. Changes in revenue requirements will be collected from all utility customers, resulting in either higher or lower bills. DERs can benefit ratepayers by avoiding costs related to electricity generation, transmission, and distribution, thereby decreasing revenue requirements. On the other hand, utility or DSP funding for DER projects and programs may increase revenue requirements, thereby raising costs for all utility customers.
- Participants are those customers who partake in DER programs, and/or install distributed energy resources. These customers are directly impacted by any upfront costs required for participation and by reduced electricity bills or direct payments based on the services they provide to the grid. Participants may experience a range of other benefits, such as increased property values, increased thermal comfort or noise reduction, and improved health and safety. Participants are primarily interested in reducing their electric bill or maximizing the payments they receive without incurring excessive expenses or inconveniences.
- Society refers to all members within a certain boundary. Society can be defined using different boundaries such as the state, the country, or the world. Members of society are impacted by all of the costs and all of the benefits that result from DER implementation, including any increased utility revenue requirements, avoided energy and capacity costs, as well as environmental impacts, economic development impacts, and reduced tax burdens.

3.2. Universe of Costs and Benefits

Distributed energy resources impose both costs and benefits on the utility system, participants, and society in general. To encourage investments that will achieve New York's energy policy goals, all costs and benefits that impact those goals should be taken into account. The table below provides an overview of the universe of costs and benefits that may be attributed to distributed energy resources, grouped by the party experiencing the impact. A detailed discussion of the impacts in each category is provided in subsequent sections.

Table 5. Universe of Relevant Costs and Benefits of DERs

	BENEFITS			COSTS		
		Category	Examples		Category	Examples
Impacts on All Customers	1	**Load Reduction & Avoided Energy Costs**	Avoided energy generation and line losses, price suppression	1	**Program Administration Costs**	Program marketing, administration, evaluation; incentives to customers
	2	**Demand Reduction & Avoided Capacity Costs**	Avoided transmission, distribution, and generation capacity costs, price suppression	2	**Utility System Costs**	Integration capital costs, increased ancillary services costs
	3	**Avoided Compliance Costs**	Avoided renewable energy compliance costs, avoided power plant retrofits	3	**DSP Costs**	Transactional platform costs
	4	**Ancillary Services**	Regulation, reserves, energy imbalance			
	5	**Utility Operations**	Reduced financial and accounting costs, lower customer service costs			
	6	**Market Efficiency**	Reduction in market power, market animation, customer empowerment			
	7	**Risk**	Project risk, portfolio risk, and resliency			
Participant Impacts	1	**Participant Non-Energy Benefits**	Health and safety, comfort, tax credits	1	**Participant Direct Costs**	Contribution to measure cost, transaction costs, O&M costs
	2	**Participant Resource Benefits**	Water, sewer, and other fuels savings	2	**Other Participant Impacts**	Increased heating or cooling costs, value of lost service, decreased comfort
Societal Impacts	1	**Public Benefits**	Economic development, reduced tax burden	1	**Public Costs**	Tax credits
	2	**Environmental Benefits**	Avoided air emissions and reduced impacts on other natural resources	2	**Environmental Costs**	Emissions and other environmental impacts

3.3. Impacts on All Utility Customers

Benefits to All Utility Customers

Distributed energy resources provide benefits to the utility system, reducing the costs associated with generation, distribution, transmission, and ancillary services. In addition, distributed energy resources may reduce utility financial and customer service costs, and enhance market competition and efficiency, while reducing risk. These benefits reduce the costs associated with the provision of electricity supply and related services, and thereby ultimately reduce the cost of electricity to all customers.

Table 6 below lists these utility system benefits, and the degree to which various types of distributed energy resources provide these benefits. A "G" denotes that resources in this asset category *generally* provide the benefit, "S" denotes *sometimes*, "R" denotes *rarely*, and "N" denotes *never*. Because the characteristics and capabilities of the individual resources within a resource category vary, not all resources will be able to deliver the same benefits. For example, only automated demand response resources are capable of reacting fast enough to provide frequency response; slower, manually activated demand response resources cannot provide these benefits. In order to quantify a resource's net value, the resource's specific operational characteristics and location must be taken into account.

Table 6. Possible Benefits of DERs to All Customers

Party Impacted	Benefits				Resources			
	Benefit Category			Specific Benefits	Energy Efficiency	Demand Response	Distributed Generation	Distributed Storage
Utility Customers	1	Load Reduction & Avoided Energy Costs	a	Avoided energy generation	G	S	G	S
			b	Avoided line losses	G	S	G	S
			c	Wholesale energy market price suppression	G	G	G	S
	2	Demand Reduction & Avoided Capacity Costs	a	Avoided generation capacity costs	G	G	G	S
			b	Avoided power plant decommissioning	G	G	G	S
			c	Wholesale capacity market price suppression	G	G	G	S
			d	Avoided distribution system investment	G	G	S	S
			e	Avoided transmission system investment	G	G	G	S
	3	Avoided Compliance Costs	a	Avoided renewable energy and energy efficiency portfolio standard costs	G	S	G	S
			b	Avoided environmental retrofits to fossil fuel generators	G	G	G	S
	4	Avoided Ancillary Services	a	Scheduling, system control and dispatch	N	N	N	N
			b	Reactive supply and voltage control	G	G	G	S
			c	Regulation and frequency response	G	G	G	S
			d	Energy imbalance	G	G	S	S
			e	Operating reserve - spinning	G	G	G	S
			f	Operating reserve - supplemental	G	G	G	S
	5	Utility Operations	a	Financial and accounting	G	S	S	S
			b	Customer service	G	S	S	S
	6	Market Efficiency	a	Reduction of market power in wholesale electricity markets	G	G	G	S
			b	Animation of retail market for DER products and services	G	G	G	G
			c	Customer empowerment	G	G	G	G
	7	Risk	a	Project risk	G	G	G	G
			b	Portfolio risk	G	G	G	G
			c	Resiliency	G	G	G	G

N = Never ***S = Sometimes, it depends on the characteristics of the asset***
R = Rarely ***G = Generally***

Load Reduction and Avoided Energy Costs

Electric energy costs are avoided due to a reduction in the annual quantity of electricity that distribution utilities must acquire, either through the wholesale energy market or through utility-owned central power plants. Energy efficiency reduces the quantity of electricity a customer consumes in total. In contrast, distributed generation reduces the quantity of centrally-produced, grid-supplied electricity a customer consumes.[9] Demand response typically does not reduce the total quantity of electricity consumed; instead, it reduces a customer's energy costs by shifting that customer's consumption of electricity from hours with high energy prices to lower-priced hours. In addition, demand response increases the elasticity of demand in the energy market, which can help prevent the exercise of market power during high-priced events, thus helping reduce the energy market clearing price.

Distributed storage does not avoid electricity consumption. On the contrary, because there is some level of losses associated with the operation of a storage system, distributed storage results in a net *increase* in electricity consumption, which may or may not increase fuel costs. This increase in electricity consumption is in part mitigated by the avoidance of line losses, as discussed below. In addition, when storage is used to shift the timing of consumption from peak periods to off-peak periods, distributed storage reduces electricity costs to the customer and in the market.

When DERs reduce the quantity of energy consumed from central generation stations, line losses are also avoided. Line losses result because generating facilities must transmit energy over long distances, requiring step-up transformers, long transmission lines, transmission substations, step-down transformers to distribution voltages, distribution lines, and distribution line transformers. All of these steps result in some level of line losses, averaging from 6 to 11 percent annually (Lazar and Baldwin 2011). Line losses are significantly higher when the transmission lines are more congested. By providing energy services much closer to where the energy is used, DERs avoid these high loss rates.

Wholesale energy market price suppression is another important benefit that DERs may provide. Energy efficiency and distributed generation reduce the quantity of energy purchased in the wholesale energy market, while demand response (including the use of onsite energy storage) can bid directly into the wholesale energy market, displacing higher-cost resources.[10] As a result, DERs can reduce the clearing prices in these markets. From society's perspective, some of this price suppression effect is actually a transfer of wealth, as consumers gain by paying less in the wholesale energy market, while producers lose through receiving a lower price. However, a portion of the price suppression effect is a welfare gain through utilizing more efficient resources to meet demand.

Demand Reduction and Avoided Capacity Costs

Distributed energy resources may help avoid electric capacity costs by reducing the quantity of capacity that utilities must acquire to ensure that generation will be sufficient to meet peak demand. In areas with wholesale capacity markets (including New York), this benefit may be passed on to consumers rapidly through avoided wholesale capacity market purchases if DERs are adequately accounted for or able to participate directly in the capacity market. These avoided capacity costs should be adjusted (de-

---

[9] Frequently this distributed energy is customer-sited, but not in all cases.

[10] In recent years, New York's Day Ahead Demand Response Program, which allows DR resources to bid into the day-ahead wholesale energy market, has not seen much activity (NYISO 2013a).

rated) by a performance factor, such as effective load carrying capacity, in order to arrive at deliverable capacity and allow for direct comparison with avoided traditional generators.

Another type of capacity cost that may be avoided by DERs is local transmission and distribution (T&D) infrastructure costs. DERs may delay, reduce the size of, or altogether avoid new T&D projects by reducing demand for transmission and distribution of centrally generated electricity to areas where the existing T&D capacity is reaching its limits. Distribution capacity investments are driven by local peak demand, and therefore the ability of DERs to provide benefits at the local level may differ from their impact on system peak demand. All distributed energy resources generally reduce the need for transmission investment;[11] their impact on necessary distribution investment, however, may vary by location.

Because different types of DERs have different characteristics, the quantities and types of capacity they can avoid will vary according to those characteristics. These characteristics include the availability of the resource, including the length of continuous hours of capacity it can provide, the resource's hourly availability, and the length (if any) of advance notification the resource requires in order to respond to a dispatch signal. These characteristics are particularly salient for demand response, distributed generation, and distributed storage resources, and can add significant complexity to the calculation of avoided capacity costs. This is a critically important issue, because avoided generation capacity costs and avoided T&D costs typically constitute a significant portion of the estimated benefits of demand response resources, and benefit-cost ratios can differ dramatically based on how avoided capacity costs are calculated (Woolf, Malone, Schwartz, et al. 2013).

Avoided Compliance Costs

By providing renewable energy, reducing electric load, and avoiding generation from fossil-fueled central station power plants, distributed energy resources may reduce the costs required to comply with RPS targets, energy efficiency portfolio standards, and state and federal environmental compliance regulations.

Electric utilities are typically required to comply with state and federal laws governing the release of certain pollutants into the environment. Environmental compliance costs may take the form of pollution control equipment and maintenance, permit fees, emission fees, and renewable energy certificates. By avoiding generation from fossil-fueled central station power plants, distributed energy resources may reduce the costs required to comply with current and future environmental regulations. For example, DERs that result in reduced energy consumption typically reduce emissions of regulated pollutants such as SO_2, NO_X, and CO_2, and may help states comply with regulations for water and waste disposal through reduced operation of central station power plants. However, the environmental impacts of DERs can

[11] There may be exceptions to this rule due to exceptionally high penetration levels or high concentrations in certain locations of distributed generation and storage. For example, Black & Veatch reports that the "heavy concentration of future distributed PV in one location (Phoenix) may impact transmission planning and integration costs due to limited geographic diversity for PV generation, especially in 2030" (Black & Veatch 2012).

vary significantly by distributed resource, by utility, and by region. The impacts will also depend on which power plants are displaced by the DER.

Avoided Ancillary Services

Ancillary services support the transmission of capacity and energy and help to maintain grid reliability and power quality. The Federal Energy Regulatory Commission (FERC) has defined six ancillary services: 1) scheduling, system control, and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service (FERC 1996).

Each region of the country defines and procures these services in specific ways. Reactive supply and voltage control (called "voltage support" by the NYISO) is the ability to maintain a specific voltage level through producing or absorbing reactive power. Regulation and frequency response is the continuous balancing of supply and demand to maintain interconnection frequency at 60 Hz, through raising or lowering output using automatic generation control (AGC) to follow moment-by-moment changes in load or supply. Energy imbalance service in New York is primarily addressed through the real-time energy market. Operating reserves provide backup generation or load reduction during system contingency events (NYISO 2013b). Currently, New York procures both spinning and non-spinning reserves that are capable of responding within either 10 minutes or 30 minutes. Black start capability service is also an ancillary service provided in New York, which refers to the ability of a generation unit to begin operating and delivering power from a shutdown condition without any assistance from a power system (NYISO 2014). In New York, voltage support and black start capability service are provided at embedded cost,[12] while regulation and frequency response, energy imbalance service, and operating reserves are procured at market-based prices (NYISO 2013b).

Depending on the market rules and on how quickly and reliably DERs can be dispatched, DERs may be able to provide the operating reserves necessary for the system to respond quickly to transmission or generator failures, to assist in responding to short-term and mid-term fluctuations in generation, and to ensure grid reliability.

In addition, there is increasing interest in using demand response programs as a relatively low-cost option to integrate variable energy resources such as wind and solar photovoltaics into the electricity system. For example, certain types of demand response resources and distributed storage can provide load following and frequency regulation services that can help maintain system stability and reliability when relatively high levels of variable resources are added to the system. Demand response programs and storage technologies could be specifically designed to provide load following and frequency regulation benefits, e.g., through pre-programmed responses to real-time prices, or through direct minute-by-minute or even second-by-second control of equipment such as water heaters, chillers, or batteries, electric vehicles, or other storage devices.

[12] Embedded costs are also referred to as "accounting costs." These costs are the actual, historical costs incurred to provide the service.

Through provision of these services, distributed energy resources have the potential to reduce market clearing prices or embedded costs for acquiring these services, while improving the efficient use of generation resources, including the integration of variable energy resources.[13] As increasing quantities of variable resources are added to the electric system and (b) increasing quantities of end-use demand response and storage technologies are installed in homes and businesses, the benefits associated with the provision of ancillary services could increase significantly.

Distributed energy resources, particularly demand response and energy storage, may provide ancillary services that improve reliability or that deliver the same quantity of reliability at a reduced cost as compared to traditional generation resources. To the extent that the reliability service provided by DERs is equivalent to the avoided central station generation that would have otherwise provided the same service, there is no net impact on the level of overall system reliability (CPUC 2010; NPCC 2010). However, if a distributed energy resource is capable of providing ancillary services more quickly or accurately than a traditional generator, the reliability benefits of DER may be positive. The converse may also hold true: if a generator with black start capability is displaced on a one-to-one basis with a day-ahead demand response program that has limits on how often and how long it can be called upon, the demand response may in fact reduce long- and short-term reliability (Freeman, Sullivan & Co. 2008).

Another consideration is the timing of when an emergency situation occurs. If the emergency situation occurs during the system peak, when most demand response programs were expected to be deployed anyway, then they may provide little additional reliability benefit. On the other hand, if an emergency situation occurs during an off-peak period when demand response resources were not expected to be deployed, those programs that can be deployed may provide a significant reliability benefit to the system.

Utility Operations

Utilities may have the ability to reduce certain categories of financial and customer service costs through the use of distributed energy resources. These include reduced arrearages, reduced carrying costs on arrearages (interest), reduced bad debt written off, and rate discounts (Tetra Tech, Inc. 2011; Hall and Riggert 2002). These benefits frequently arise when access to distributed energy resources is provided to low-income customers. As energy-efficient technologies or distributed generation resources reduce energy bills for low-income participants, the likelihood that customers experience difficulties with paying their utility bills is also reduced, which in turn decreases costs associated with events such as arrearages and late payments. In addition, utilities may experience reduced customer service costs. As customers are better able to pay their utility bills on time, the utility need engage in fewer customer calls, late payment notices, shut-off notices, terminations, reconnections, and other collection activities. These benefits accrue to the utility through savings in staff time and materials (Tetra Tech, Inc. 2011).

[13] One way that distributed storage (or any DER with a storage element) may increase system efficiency is through *increasing* demand during periods of low prices or when variable renewable resources would otherwise be curtailed. This energy is then saved for use at a later time when energy prices are high and inefficient peaker generation would otherwise be dispatched.

In some cases, DERs may improve safety. As electric load during peak periods is reduced, utilities may experience reduced safety-related emergency calls and insurance costs due to reduced fires and other emergencies (Tetra Tech, Inc. 2011).

Market Efficiency

Distributed energy resources can improve market efficiency at both the wholesale and retail market level. At the wholesale market level, the participation of DERs in the market increases the elasticity of demand or expands the number of potential suppliers. This increases market competition and reduces the ability of suppliers to exercise market power.

At the retail level, adoption of DERs increases the number of market actors involved in supplying energy products and services, facilitating both competition and innovation. This effect is referred to as "market animation" and was described in the Staff's Track One Straw Proposal.[14] At the individual customer level, DERs empower customers to take control of their utility bills and usage, enabling customers to make consumption decisions that more accurately reflect the actual value that they place on the product or service.

Risk

Risk issues are discussed in Chapter 5.

Costs to All Utility Customers

Costs to all utility customers primarily include costs to administer, implement, and integrate distributed energy resources. All else equal, these costs increase utility revenue requirements, thereby increasing costs to all utility customers. These costs are typically incurred by the utility and are then passed through to utility customers in rates. Table 7 below presents the cost categories, separated into program administration costs, utility system costs, and DSP costs, each of which include sub-categories of costs.

[14] Staff writes: "Creating animated DSP markets as envisioned in REV implies that customers will increasingly: 1) be aware of and adopt DER technologies and services; and 2) use DER technologies in such a manner as to optimize their value to the grid and to the customer" (NY DPS Staff 2014a, 2).

Table 7. Possible Costs of DERs to All Utility Customers

<table>
<tr><th rowspan="3">Party Impacted</th><th colspan="4">Costs</th><th colspan="4">Resources</th></tr>
<tr><th colspan="2" rowspan="2">Cost Category</th><th colspan="2" rowspan="2">Specific Costs</th><th rowspan="2">Energy Efficiency</th><th rowspan="2">Demand Response</th><th rowspan="2">Distributed Generation</th><th rowspan="2">Distributed Storage</th></tr>
<tr></tr>
<tr><td rowspan="12">Utility Customers</td><td rowspan="6">1</td><td rowspan="6">Program Administration Costs</td><td>a</td><td>Program / project administration</td><td>G</td><td>G</td><td>S</td><td>S</td></tr>
<tr><td>b</td><td>Program / project marketing</td><td>G</td><td>G</td><td>S</td><td>S</td></tr>
<tr><td>c</td><td>Program / project evaluation costs</td><td>G</td><td>G</td><td>S</td><td>S</td></tr>
<tr><td>d</td><td>Incentives to customers to offset incremental measure costs</td><td>G</td><td>G</td><td>S</td><td>S</td></tr>
<tr><td>e</td><td>Incentives to customers for taking action or changing behavior</td><td>G</td><td>S</td><td>S</td><td>S</td></tr>
<tr><td>f</td><td>Capital costs</td><td>R</td><td>G</td><td>S</td><td>S</td></tr>
<tr><td rowspan="5">2</td><td rowspan="5">Utility System Costs</td><td>a</td><td>Increased energy consumption</td><td>N</td><td>S</td><td>N</td><td>G</td></tr>
<tr><td>b</td><td>Environmental compliance costs</td><td>N</td><td>S</td><td>N</td><td>S</td></tr>
<tr><td>c</td><td>Integration costs - distribution system</td><td>N</td><td>R</td><td>G</td><td>S</td></tr>
<tr><td>d</td><td>Integration costs - transmission system</td><td>N</td><td>N</td><td>R</td><td>R</td></tr>
<tr><td>e</td><td>Integration costs - ancillary services</td><td>N</td><td>N</td><td>G</td><td>N</td></tr>
<tr><td>3</td><td>DSP Costs</td><td>a</td><td>Platform costs - advanced distribution system management, capital, and operating expenses</td><td>S</td><td>G</td><td>G</td><td>G</td></tr>
</table>

N = Never ***S = Sometimes, it depends on the characteristics of the asset***
R = Rarely ***G = Generally***

Program Administration Costs

At a high level, program administration costs can be divided into those costs required to design, approve, and implement programs and services, financial incentives to customers, and capital costs necessary to support these functions. It is anticipated that these costs will be incurred by the Distributed System Platform operator, whether the utility or a third party, and that the costs will be passed on to all utility customers.

Program costs include operations and maintenance costs; marketing and outreach costs; and evaluation, measurement, verification (EM&V) costs. For some distributed energy resources, participation in the wholesale capacity and/or energy markets may require long lead times, financial guarantees, and unique administrative costs. For example, to bid demand response as a resource in day-ahead, real-time, ancillary services, or forward capacity markets, there may be costs associated with registering for market participation, certifying baseline customer load, submitting market offers, and participating in auctions that are unique to participating in wholesale markets and incremental to the administrative costs of offering retail demand response programs.

Some DER programs provide financial incentives to customers to encourage them to take a certain action or change their behavior. For example, in demand response programs, peak time rebate programs offer customers direct rebates for curtailing demand during peak hours. The cost of these financial incentives that is not recovered through payments from the wholesale capacity market is passed on to all utility customers. Some DER programs provide financial incentives to customers to help offset a portion of the incremental measure cost, e.g., rebates for more efficient lighting.

Finally, capital costs reflect investments in equipment with relatively long lives (e.g., information technology equipment, communications technologies, and demand control technologies) used to administer the program.

Utility System Costs

Costs associated with distributed energy resources include any costs incurred by the utility to interconnect and integrate distributed energy resources, as well as any additional costs incurred due to increased emissions or greater electricity consumption.[15]

Interconnection costs pertain primarily to distributed generation. While low levels of distributed generation may pose little interconnection costs, beyond a certain level of penetration, the utility may experience reliability and power quality issues unless upgrades to the distribution system are made. Distribution system investments may be required to support voltage regulation, upgrade transformers, increase available fault duty, and provide anti-islanding protection (Bird et al. 2013).

Examples of typical distribution upgrades are listed by penetration level in the table below, using distributed solar PV as an example.

Table 8. Typical Distribution System Upgrades for Distributed Solar Integration

Penetration Level	Typical Distribution Upgrades
Low penetration	Switching devices, line extensions
Average penetration	Cable/conductor upgrades, protection devices, voltage regulating devices
High penetration	New distribution circuits
Very high penetration	Substation transformer upgrades
Extreme penetration	Sub-transmission/transmission upgrades

Source: (Rodriguez 2012)

Integration costs are the operating costs associated with managing distributed energy resources, particularly distributed generation, distributed storage, and demand response. These costs include scheduling, forecasting, and controlling DERs, as well as procurement of additional ancillary services such as reserves, regulation, and fast-ramping resources.[16] These costs tend to be highly dependent on the penetration level of DERs, the location of DERs, and the performance characteristics of the existing generation mix (RMI 2013). The utility may also incur additional administrative costs to review applications to install DERs, additional billing costs, and possibly customer service costs related to customer communication and DER support (Bird et al. 2013).

It is important to note that DER interconnection and integration costs may be mitigated by other DER investments. For example, the need for distribution system upgrades may be mitigated in part through

[15] Utility lost revenues are not included in the costs to the utility system, as these costs will be recovered from customers through higher rates. They are therefore already accounted for under impacts to all customers.

[16] The need to procure fast-ramping resources or reserves is due to both the inflexibility of many fossil-fired units and the variability of most renewable generation.

the installation of smart inverters, distributed storage, and other advanced enabling infrastructure and technologies. Demand response and distributed storage may facilitate the integration of variable distributed generation resources through quickly modifying load or supply to match the distributed generator's profile. Thus, as the level of distributed solar penetration increases, the value of certain other distributed technologies will also increase. A comprehensive benefit-cost analysis should investigate how portfolios of resources can be optimized in order to account for these synergies.

Other costs may arise due to increased net electricity consumption. As discussed earlier, energy storage always increases net electricity consumption, while demand response sometimes results in increased electricity consumption. For example, a demand response program that shifts air conditioner load from peak to off-peak hours may result in a net increase in the total electricity consumption through pre-cooling to a temperature lower than normal, and then rapidly cooling again following the curtailment event. These costs from increased energy generation, transmission, and delivery represent an incremental cost that should be attributed to the distributed energy resource, although these will typically be more than offset by reduced energy costs in other hours (as explained in the benefits section above). It may be useful to present the costs of increased energy consumption separately from the avoided energy costs, as opposed to presenting the net impact on energy, as the costs and avoided costs per unit of energy consumption will differ by hour. Electricity purchases or generation during off-peak hours will generally cost less than during on-peak hours, typically resulting in net savings once the avoided costs of generation are factored in.

Some DERs may also increase the costs required to comply with current and future environmental regulations.[17] For example, a load curtailment program might require a customer to operate a fossil-fired backup generator that produces SO_2, NO_X, greenhouse gases such as CO_2, and other air emissions. Any incremental costs of complying with environmental regulations should be accounted for in the cost imposed by the DER program.

Distributed System Platform Costs

The DPS Staff Straw Proposal on Track One Issues identifies three primary functions of the operator of the Distributed System Platform (DSP):

1) Provision of data to market actors, management of customer and third-party participation, and facilitation of customer engagement;
2) Monitoring and dispatch of market-based distributed energy resources; and
3) Distribution planning and construction (NY DPS Staff 2014a).

Through these functions, a "flexible platform for new energy products and service delivery" will be created (NY DPS Staff 2014a, 13). To the extent that these functions represent entirely new or expanded responsibilities, additional costs will be incurred to create this platform. These platform costs will be

[17] These costs of environmental compliance should not be confused with environmental externalities, which are discussed under Costs and Benefits to Society.

eventually passed on to utility customers, and should therefore be accounted for in the framework. However, those costs that would be incurred regardless of DER investments do not represent incremental costs, and should be excluded from the framework.

3.4. Participant Impacts of DERs

Participants of DER programs experience cost and benefits that extend beyond the impacts that all utility customers experience as a result of DER deployment.

Participant Benefits

There are a variety of benefits that accrue to participants from distributed energy resources, ranging from O&M cost savings to improved comfort, as shown in Table 9. Depending on the perspective of the policymaker, revenues from participating in wholesale capacity and/or energy markets are generally excluded from participant benefits in the valuation framework. These payments are excluded because the same service or good is being purchased from the wholesale market as before; the only change is in the entity providing the good or service.[18]

Table 9. Possible Participant Benefits of DERs

Party Impacted	Benefits					Resources			
	Benefit Category			Specific Benefits		Energy Efficiency	Demand Response	Distributed Generation	Distributed Storage
Participants	8	Participant Non-Energy Benefits	a	Participant's utility savings (time addressing billing, disconnection, etc.)		G	S	S	S
			b	Low-income-specific		G	G	G	G
			c	Improved operations		G	N	R	S
			d	Comfort		G	N	N	N
			e	Health and safety		G	N	R	R
			f	Tax credits to participant		G	R	G	S
			g	Property improvements		G	R	S	S
	9	Participant Resource Benefits	a	Other fuels savings		S	N	N	S
			b	Water and sewer savings		S	N	N	N

N = Never ***S = Sometimes, it depends on the characteristics of the asset***
R = Rarely ***G = Generally***

Specifically, benefits of DERs to customers that install them can be described as follows:

- Participant utility savings: To the extent that DERs reduce electric bills, payment-troubled participants may experience reduced opportunity costs and transaction costs related to service

[18] A reduction in the quantity of a good or service purchased from the wholesale market does have direct benefits; these were discussed under benefits to all utility customers. Or, if the good or service is provided at a lower cost, this would be counted as a benefit. However, a change only to the party that is paid for providing the good or service does not generally constitute a net benefit. That is, if the policymaker is indifferent as to which member of society is providing the good or service (e.g., whether it is a merchant generator, utility, third-party DER provider, or utility customer), then there is no net impact on social welfare. If, however, the policymaker wishes to limit the analysis to only utility customers, then the purchase of electricity services from a customer with solar PV rather than a merchant generator would be counted as a benefit.

disconnections and reconnections, bill-related calls to the utility, and bill collection. Further, participants may experience greater control over their utility bills and be insulated from energy price increases (Tetra Tech, Inc. 2011; Hall and Riggert 2002; SERA 2010).

- Low-income specific: Low-income households spend a disproportionate amount of their income on energy when compared to the population at large; therefore, reducing energy costs has particularly significant benefits for low-income customers. Reduced energy costs may improve economic stability and lead to a reduction in relocations for low-income households, while allowing income to be used for healthcare, education, and other important uses. Owners of low-income rental properties may also experience benefits, including improved marketability of rental units, reduced tenant turnover, reduced property maintenance expenses, and reduced tenant complaints (Tetra Tech, Inc. 2011).
- Improved operations: Participants may experience reductions in O&M costs and reduced spoilage/defects due to improved equipment performance, longevity, and functionality. Customers may also experience reduced labor costs, reduced administration costs, improved employee productivity, and increased sales revenue due to enhanced indoor environmental quality and aesthetics (Tetra Tech, Inc. 2012; NZ EECA 2012).
- Comfort: Participants may experience greater perceived comfort, particularly from energy efficiency improvements. For example, energy efficient investments may reduce noise, improve lighting, and enhance thermal comfort (Tetra Tech, Inc. 2011; SERA 2010).
- Health and safety: Distributed energy resources may have direct impacts on health and safety through improved home environments and self-supplied electricity generation during grid outages. Energy efficiency may reduce the risk of hypothermia or hyperthermia (particularly during heat waves and cold spells), reduce fire and carbon monoxide risks, and decrease excess moisture and mold, leading to amelioration of asthma triggers and other respiratory ailments (Tetra Tech, Inc. 2011; SERA 2010; NZ EECA 2012).
- Tax benefits to participants: Federal, state, and local tax credits, exemptions, or abatements may reduce the installation or ongoing costs to participants. Participants may qualify for the Federal Residential Renewable Tax Credit, sales tax exemption, and property tax exemption or abatement.[19]
- Property improvements: The installation of customer-sited distributed energy resources may increase property values due to the improved durability, reduced maintenance (for some DERs), and lower electric bills for these properties. DERs may not only increase the resale or rental

[19] Tax benefits may include: the NY Residential Solar Tax Credit, the Federal Residential Renewable Tax Credit, NY Property Tax Exemption for Renewables (local option, expires Dec. 31, 2014), Energy Conservation Improvements Property Tax Exemption, Property Tax Abatement for PV in New York City (expires Dec. 31, 2014), Sales Tax Exemption for Solar PV (and thermal) in some locations. See www.dsireusa.org for details on these incentives.

value, but may also improve the ease of selling or renting the property (Tetra Tech, Inc. 2011; SERA 2010).

Participant Costs

Customers that install distributed energy resources may also incur costs above and beyond the costs of these resources to all ratepayers. These costs vary by resource, but frequently include contributions toward a measure (e.g., solar panels or efficient appliances), increased O&M costs, and transaction costs, as well as a range of indirect costs, as shown in Table 10.

Table 10. Possible Participant Costs of DERs

Party Impacted	Costs				Resources			
	Cost Category		Specific Costs		Energy Efficiency	Demand Response	Distributed Generation	Distributed Storage
Participants	4	Participant Direct Costs	a	Capital costs (contribution to DER measures)	G	G	G	G
			b	Transaction costs	G	G	G	G
			c	Annual O&M costs	G	G	G	G
	5	Other Participant Impacts	a	Increased heating or cooling costs	S	N	N	R
			b	Value of lost service from curtailment	N	G	N	N
			c	Reduced comfort	S	S	S	N

N = Never ***S = Sometimes, it depends on the characteristics of the asset***
R = Rarely ***G = Generally***

Direct costs include a participant's contribution toward an energy efficiency measure, demand response measure, or distributed generation or storage resource. Direct participant costs also include money spent on operation, and maintenance, as well as time and effort associated with gaining knowledge about equipment or programs, deciding whether or how to install equipment, filling out program applications, undertaking energy audits, and developing and managing a load reduction plan.

Other participant impacts may not be as readily apparent, but include impacts to participants that arise as a result of DERs. In the case of demand response, the participant's value of lost service includes any losses in productivity that occur because of demand reductions, e.g., reduced production when a business shuts down some of its equipment during a demand response event. (If any of this productivity is shifted to another time period, the value of lost service would be based only on net productivity losses plus any costs associated with shifting work from one time period to another.)

Participants may also experience other costs due to modified electricity consumption or more efficient appliances, such as losses in comfort when particular end uses become unavailable (e.g., higher household temperatures during an air conditioning cycling event), or a different quality of light from more efficient bulbs.

3.5. Societal Impacts of DERs

Societal Benefits

Societal benefits are primarily comprised of reduced costs borne by the public, as well as environmental benefits that represent improvements in public goods such as air and water quality and land impacts, as shown in Table 11.

Table 11. Possible Societal Benefits of DERs

Party Impacted	Benefits				Resources			
	Benefit Category			Specific Benefits	Energy Efficiency	Demand Response	Distributed Generation	Distributed Storage
Society	10	Public Benefits	a	Economic development	G	G	G	G
			b	Tax impacts from public buildings	G	G	G	G
	11	Environmental Benefits	a	Avoided air emissions	G	S	G	S
			b	Other natural resource impacts	G	G	S	S

N = Never S = Sometimes, it depends on the characteristics of the asset
R = Rarely G = Generally

The potential societal benefits of DERs include:

- Economic development: Distributed energy resources may reduce the costs of business or expand business opportunities, resulting in job creation and expanded economic output (Tetra Tech, Inc. 2011; SERA 2010).
- Tax impacts: Lower electric bills for public buildings (schools, government offices, etc.) reduce the tax burden on the general public.
- Air emissions: By reducing the need to generate, transmit, and distribute electricity from central station power plants, DERs can reduce emissions of:
    - Greenhouse gases (such as carbon dioxide and methane),
    - Criteria air pollutants (ozone, particulate matter, carbon monoxide, nitrogen oxides, sulfur dioxide, lead)
    - Mercury, and
    - Other toxins.

  Although some of the benefits of avoiding these emissions flow to utility customers through reduced environmental compliance costs, the social benefit from reduced emissions typically greatly exceeds compliance costs.[20] The societal benefits from reduced air emissions (beyond

[20] Economic theory generally dictates that the marginal emissions abatement cost should be set equal to the marginal benefit of abatement to society. The marginal benefit of abating a unit of emissions typically declines as abatement increases, while the marginal cost increases as abatement increases. Therefore it is reasonable to expect that the social value of avoided emissions is much higher than the abatement costs. This additional value is accounted for as a benefit to society, while the (much smaller) value of avoided compliance costs are accounted for as a benefit to all utility customers. See, for example, Lazar and Colburn (2013).

avoided compliance costs) include improved health and productivity, reduced crop damage, and increased recreation value and economic activity associated with improved visibility (EPA 2011).

- Other natural resource benefits: Avoiding thermal generation can have significant benefits for water and land resources.
    - Most thermal power plants withdraw massive quantities of water for cooling purposes, impinging fish on filter screens and cooking their eggs and larvae, and release this heated water back into estuaries and rivers, raising the temperature of their ecosystems. Natural gas, coal, and uranium mining and combustion may contribute to water scarcity and contaminate water resources through spills, leaks, and waste disposal (Whited, Ackerman, and Jackson 2013; Fisher et al. 2011).[21]
    - Centralized generation and the transmission lines used to transport electricity from these sources also have significant impacts on terrestrial ecosystems. Mining and transporting fuel for central station thermal power plants (coal, oil, natural gas, and nuclear) can result in widespread habitat destruction and fragmentation, as well as soil and water contamination (Keith et al. 2012).[22]

Societal Costs

In some cases, distributed energy resources impose costs on society, primarily through increased taxes and environmental externalities.

Table 12. Possible Societal Costs of DERs

Party Impacted	Costs				Resources			
	Cost Category		Specific Costs		Energy Efficiency	Demand Response	Distributed Generation	Distributed Storage
Society	6	Public Costs	a	State tax credits	S	R	G	S
			b	Federal tax credits	S	R	G	S
	7	Environmental Costs	a	Environmental externalities	N	S	N	S

N = Never S = Sometimes, it depends on the characteristics of the asset
R = Rarely G = Generally

Tax credits, while reducing costs to participants, increase the tax burden for other members of society. The degree to which these costs are taken into account depends on the evaluation perspective adopted by the policymaker. For example, New York may wish to include only the costs of federal tax credits

---

[21] Coal and nuclear units produce large quantities of toxic waste, much of which ends up in sludge ponds and landfills that can leak or leach into the environment over time. Waste from coal plants includes coal combustion residuals and flue gas desulfurization waste. This waste from the U.S. coal fleet amounts to the equivalent of two-thirds of all the landfilled municipal solid waste (garbage) generated in the United States (Fisher et al. 2011). Groundwater contamination can also occur during natural gas extraction.

[22] This is particularly evident in mountain-top removal used in the Appalachian Mountains and open-pit mining methods used in the Mountain West.

borne by New York taxpayers. Tax credits may also create market distortions, but such impacts are not included in this report.

As noted above, some DERs may increase net emissions, at least temporarily. Demand response provided by backup generators has the potential to increase particulate matter and other air emissions for a period of time. Even if these emissions do not increase the cost of compliance with environmental regulations, the release of toxic emissions from backup generators may impose costs on the public in the form of aggravated chronic respiratory conditions, leading to increased mortality and morbidity (OEHHA/ALA). In addition, integration of larger quantities of variable resources (such as solar PV) may cause central station generators to operate less efficiently, increasing emissions from such generators. Although this impact is likely small relative to the emissions avoided through increased low-carbon distributed generation, the costs imposed on society through these higher central station emissions rates should be accounted for in the framework.

4. ALTERNATIVE APPROACHES TO ACCOUNT FOR DER IMPACTS

Many DER impacts, such as avoided energy costs, have already been quantified and monetized by New York regulators and utilities. Such impacts can be immediately incorporated into cost-benefit analyses and improved over time as new information or techniques become available.

Other DER impacts have not yet been addressed or monetized. For some of these impacts, developing monetary values may currently be infeasible or impractical. Data may be unavailable, studies may require a considerable amount of time and resources to implement, and the results of such studies may still result in a high degree of uncertainty.

Despite these challenges, DER impacts should not be excluded or ignored on the grounds that they are difficult to quantify or monetize. Approximating hard-to-quantify impacts is preferable to assuming that those costs and benefits do not exist or have no value.

Alternative approaches to estimating DER impacts include:

1. Proxies,
2. Alternative benchmarks,
3. Regulatory judgment, and
4. Multi-attribute decision analysis.

Proxies assign a monetary value to impacts, allowing them to be directly incorporated into the net present value of an investment. Proxies, alternative benchmarks, and regulatory judgment may be used individually or in conjunction with multi-attribute decision analysis. Multi-attribute decision analysis provides a framework for systematically and transparently accounting for both monetized and qualitative impacts across a set of investment options. Each of these approaches is discussed in more detail in this chapter.

Alternative valuation approaches may be used in New York in the short term to account for impacts that are difficult to value. Over time, more detailed, New York-specific estimates of DER hard-to-quantify impacts can be developed. To ensure progress is made on this front, New York regulators should clearly articulate the approach to be used for developing impact estimates, including general timeframes for completing more detailed evaluations for impacts that have been identified as a priority for the state. Yet the process does not end once values have been developed. Regulators and stakeholders should continually update the range of DER impacts included in the framework to ensure they measure progress toward state energy policy goals, capture the effects of new technologies, and reflect the best available data and estimation techniques.

DER impacts should not be excluded or ignored on the grounds that they are difficult to quantify or monetize. Approximating hard-to-quantify impacts is preferable to assuming that those costs and benefits do not exist or have no value.

The types of DER impacts that are likely to currently require an alternative valuation approach include:

Table 13. Impacts that May Require Alternative Valuation Techniques

	Benefits	Costs
All Customers	Customer empowerment	
Participants	Utility savings	Transaction costs
	Low-income specific benefits	Annual O&M Costs
	Improved operations for participants	Increased heating or cooling costs
	Improved comfort	Reduced comfort
	Improved health and safety	Value of lost service
	Property improvements	
Society	Reduced environmental impacts	Increased environmental impacts
	Increased economic development	Reduced economic development

4.1. Proxy Values

For those DER impacts that are not readily monetized, the next best option is to use a proxy to account for the DER impacts. The primary advantage of a proxy is that it translates a qualitative impact into monetary terms, which can then be added to the other monetary values.

Proxies should not be developed as arbitrary values. Instead, regulators and other stakeholders can develop proxies by making educated approximations based upon the best information currently available regarding the relevant impact or impacts. This should include a review of relevant literature on the specific impact or impacts. It should also include a review of proxy values used by other states.

Proxy Types

Options for proxy values include avoided cost multipliers (percentage adders), electricity multipliers ($/MWh), and other multipliers (e.g., $/MW and $/MMBtu).

Avoided Cost Multiplier (Percentage Adder)

The avoided cost multiplier (percentage adder) approximates the value of non-monetized DER impacts relative to the more easily quantified avoided costs. It can be applied by increasing the DER avoided costs (typically avoided energy and capacity costs) by a pre-determined percentage. This is the simplest and most commonly used method for non-energy benefit proxies. Examples are given in the section titled "Experience from Other Jurisdictions" below.

However, this approach suffers from the fact that there may not be a strong correlation between the value of avoided costs and the value of other DER impacts. Consequently, as avoided costs change over time, the value of the non-monetized DER impacts will change commensurately, even though the non-monetized DER impacts themselves may not change at all.

Electricity Multiplier ($/MWh)

An electricity multiplier approximates the value of non-monetized DER impacts relative to the quantity of electricity generated or saved by a DER asset. This proxy may be more closely correlated with actual DER impacts relative to an avoided cost multiplier, but it is not well suited for DER resources that primarily provide capacity rather than energy (e.g., demand response programs) or programs that avoid consumption of non-electric fuels (e.g., natural gas, oil). Also, the accuracy of this type of proxy depends upon the mix of end-use measures offered by the program. As the mix changes over time, the multiplier will need to be changed accordingly.

This proxy can be derived in several ways, including: (a) from an avoided cost multiplier; (b) from applying DER impacts dollar values to electricity savings; or (c) from an analysis of the DER impacts values applied in other states.

Other Multipliers

Other multipliers include a $/MW multiplier, a $/MMBtu multiplier, and a $/unit multiplier. The $/MW multiplier may be used to capture the non-monetized benefits of resources primarily providing capacity benefits (such as the risk mitigation provided by direct load control demand response programs).

A multiplier in terms of $/MMBtu approximates the value of specific impacts relative to all of the fuel savings from a type of energy efficiency or other DER program (i.e., electricity, gas, oil, etc.). However, as the mix of measures offered by the program changes over time, and the relative amounts of different fuel savings change, then the multiplier should be modified to reflect the new mix of measures.

Proxy Granularity

Proxy values can be developed at different levels of granularity, ranging from a single proxy value that applies to an entire portfolio of DER resources to different proxy values for each DER impact. In particular, proxies can be developed at the following levels of detail:

- Portfolio-level proxy: Develop a single proxy value for a specific impact that would be applied to all DER, including energy efficiency, demand response, and distributed generation resources. This approach is likely to be much less accurate and transparent than all of the approaches listed here. This approach is not able to capture the significant differences in impacts that exist between DER types, programs, and customer sectors.
- Resource-level proxies: Develop separate proxy values for a specific impact that would be applied separately to energy efficiency, demand response, and distributed generation resources. For example, this approach could be used to develop a separate proxy value for all participant non-energy benefits for each of these three resource types. This would be a significant improvement over portfolio level proxies, for any impact that varies significantly between DER types.
- Sector-level proxies: Develop proxy values for a specific impact for each customer sector (e.g., residential, low-income, commercial, industrial). For example, this approach could be used to develop a separate proxy value for all participant non-energy benefits for each sector. This approach would be an improvement over resource-level proxies for any impact that varies significantly across customer sectors.

- Program-level proxies: Develop proxy values for a specific impact for each type of DER program. For example, this approach could be used to develop separate proxy values for all participant non-energy benefits of each type of energy efficiency program (e.g., residential home energy retrofits, commercial and industrial new construction). This approach would be an improvement over sector-level proxies, for any impact that varies significantly across programs.
- Impact-level proxies: Develop proxy values for a specific impact. For example, this approach could be used to develop separate proxy values for each of the participant non-energy benefits (e.g., improved operations, low-income, comfort, health and safety). This approach is more detailed, more transparent, and likely to be more accurate than all of the other approaches listed here. It also requires the most amount of information to develop reasonable proxies.

As indicated in the list of options above, there may be a tradeoff between accuracy and feasibility. The more detailed that a proxy can be, the more likely it is to accurately represent the magnitude of the specific impact in question. However, the more detailed the proxy, the more information (and effort) is required to determine a reasonable proxy.

Another advantage of more detailed proxies is that they are more transferrable across programs, across utilities, and over time. For example, an impact-level proxy such as improved health and safety, applied to residential retrofit efficiency programs, is likely to be generally applicable to other residential retrofit programs and remain relatively constant over time. Conversely, a sector-level proxy to account for all participant non-energy benefits for the residential sector should, in theory, be different for different programs and could change over time, as the mix of efficiency measures changes over time.

Experience from Other Jurisdictions

Several states have applied proxy values associated with participant non-energy benefits of energy efficiency programs. These values tend to be on the order of 10 to 25 percent, and are applied as an avoided cost multiplier. Table 14 presents a summary of several proxy values currently in use for the participant non-energy impacts of energy efficiency programs.

Table 14. Sample Values of Energy Efficiency Participant NEB Proxies

State / District	Proxy Multiplier for All Programs	Additional Proxy Multiplier for Low-Income Programs
CO	10%	25%
DC	10%	0
OR	10%	0
VT	15%	15%
All of these are avoided cost multipliers applied to each program.		

Sources: Woolf, Malone, Kallay, et al. 2013; Malone et al. 2013

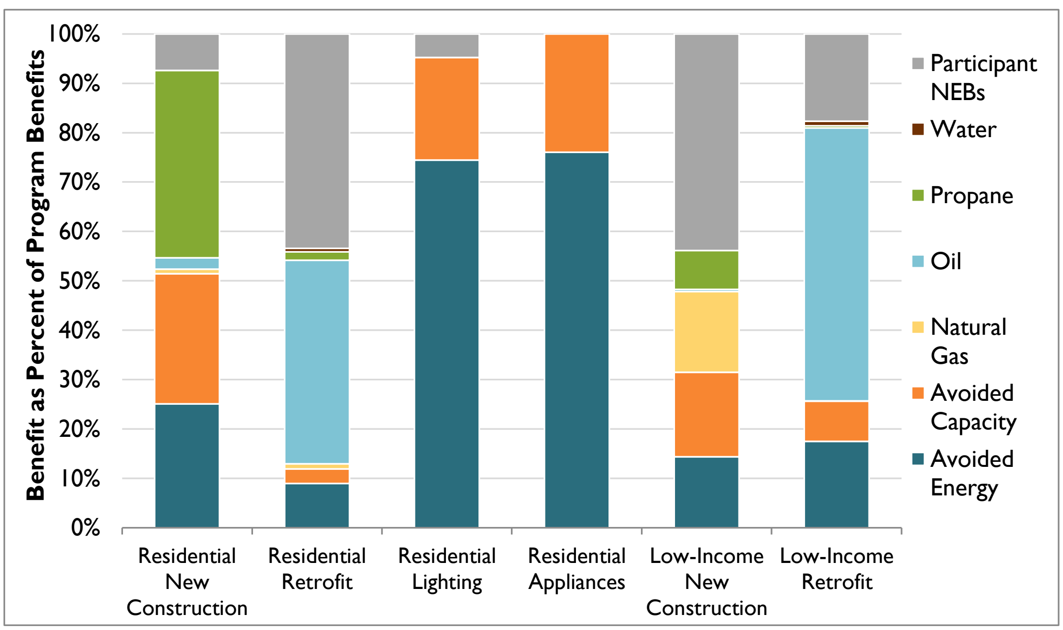
As indicated in the table, states typically apply a portfolio-level proxy for energy efficiency resources, with the exception of some additional low-income sector proxies. Also, all these values are applied as an avoided cost multiplier, as opposed to a multiplier more focused on the type of energy savings. Both of these practices suggest a reluctance to either assess the proxy value in greater detail, or to imply more precision than is available, or both.

Proxies Compared to Monetized Values

At least two states (Massachusetts and Rhode Island) have conducted studies to estimate dollar values for participant non-energy benefits (Tetra Tech, Inc. 2011; Tetra Tech, Inc. 2012). These studies are among the most detailed monetized estimates of non-energy benefits available. It is informative to compare what the results of those studies imply relative to the participant non-energy benefit proxies in use today.

Figure 1 presents an indication of the magnitude of the participant non-energy benefits for different residential programs, based upon the monetized non-energy benefit values used in Massachusetts. Each bar indicates the portion of the total benefits (in present value dollars) that are made up of participant non-energy benefits relative to other benefits, including avoided capacity and avoided energy. This chart clearly demonstrates that the magnitude of participant non-energy benefits can vary significantly by program type. It also demonstrates that for some efficiency programs, the magnitude of the non-energy benefits is significantly larger than what is assumed by the proxy values presented in Table 14 above, while for others it is lower.

Figure 1. Participant Non-Energy Benefits Currently Applied in Massachusetts



Source: Derived from Massachusetts Statewide Cost & Savings Tables (08-50 Tables), 2013 Results. (Massachusetts Energy Efficiency Advisory Council 2013)

Table 15 illustrates how proxies for participant non-energy benefits can be presented as different types ($/unit, $/MWh, $/MMBTu, and percent multiplier). The information in this table is based upon the actual Massachusetts statewide cost and savings results for 2013, using actual assumptions and values.

It starts with the participant non-energy benefit values (in present value dollars), and then estimates what the magnitudes of the different proxy types would be if it were determined from these values.

Once again, this information makes it very clear that the participant non-energy benefits values are likely to differ significantly across different sectors, and across different programs. The percent multiplier values are particularly interesting, because these can be compared directly with the state portfolio-level proxy multipliers presented in Table 14 above. For some programs, particularly commercial and industrial programs, the equivalent percent multipliers are close to the portfolio-level proxy values used by several states. However for other programs, particularly the home energy retrofit program and the low-income programs, the equivalent percent multipliers are much higher than the portfolio-level proxy values used by several states.

Table 15. Monetized Values of Participant NEBs Relative to Proxy Values

Massachusetts						
Sector / Program	**Actual Estimated NEI Value ($)**	***Equivalent $/Unit***	***Equivalent $/MWh***	***Equivalent $/MMBtu***	***Equivalent % Adder***
Residential					
Res New Constr.	2,973,977	*729*	*32*	*3*	*14%*
Home Retrofit	230,401,701	*5,063*	*524*	*32*	*365%*
Products & Services	11,880,390	*7*	*7*	*1*	*5%*
Avg. Residential	249,267,785	*94*	*89*	*9*	*63%*
Low-Income					
LI New Constr.	2,091,096	*3,154*	*334*	*20*	*139%*
Single-Family	14,787,093	*1,252*	*106*	*7*	*69%*
Avg. Low-Income	30,143,459	*842*	*95*	*9*	*70%*
Commercial & Industrial					
C&I New Constr.	27,917,270	*1,215*	*10*	*1*	*7%*
Small C&I Retrofit	34,184,135	*6,158*	*29*	*4*	*19%*
Large C&I Retrofit	91,820,037	*42,042*	*19*	*3*	*13%*
Avg. C&I	153,921,441	*5,011*	*17*	*2*	*12%*

Source: Derived from Derived from Massachusetts Statewide Cost & Savings Tables (08-50 Tables), 2013 Results. (Massachusetts Energy Efficiency Advisory Council 2013). The term "unit" is defined here as a participant in the efficiency program.

4.2. Alternative Benchmarks

Alternative screening benchmarks allows DER programs to be considered cost-effective at pre-determined benefit-cost ratios that are less (or greater) than one. This approach eliminates the need for identifying values for DER impacts by category, or by program. It is, by design, a simplistic way of recognizing that the combination of DER impacts for any one program is significant enough to influence the cost-effectiveness analysis. Regulators can choose an alternative benchmark that they are comfortable with by program, by sector, by resource type, or for a DER portfolio.

The primary advantage of this approach is that it does not require the development of specific monetary or proxy values. Instead, it is more of a general reflection of the regulators' willingness to be flexible in accounting for certain costs and benefits.

This approach is currently used in several states to account for the non-energy benefits of low-income programs. In addition, at least one state (Washington) has a policy whereby programs with a significant amount of non-monetized, non-energy benefits can be considered cost-effective as long as the benefit-cost ratio exceeds 0.667 (Woolf et al. 2012, 26).

Note that using alternative benchmarks essentially has the same effect as applying a proxy value; that is, a proxy value can be directly converted into a lower threshold and vice-versa. For example, an alternative benefit-cost ratio benchmark of 0.9 is equivalent to an avoided cost multiplier of 11%; and an alternative benefit-cost ratio benchmark of 0.8 is equivalent to an avoided cost multiplier of 25%.

Consequently, applying an alternative benchmark actually is a quantitative approach with monetary impacts. The primary difference between alternative benchmarks and proxies may simply be in the perception that alternative benchmarks are intended to be even more of a general approximation than proxies.

4.3. Regulatory Judgment

Accounting for DER impacts through regulatory judgment allows regulators to make a determination that an investment is in the public interest without identifying a specific, pre-determined screening benchmark or criterion. Regulatory judgment should always be made with the greatest amount of information available, which should include impacts that have been quantified as much as possible, even if they cannot be monetized. For example, in making a judgment about an efficiency program in which the CO_2 reduction benefits or the economic development benefits have not been monetized, regulators should consider the quantity of CO_2 emission reductions (in terms of tons avoided) and the number of jobs created (in job-years).

The primary difference between this approach and applying alternative benchmarks is that regulatory judgment can be applied more flexibly and on a case-by-case basis, whereas alternative screening benchmarks establish up front a more clearly defined process for determining cost effectiveness. For example, a commission could establish an alternative benefit-cost ratio benchmark of 0.85 for all efficiency programs to account for carbon reductions and jobs created that have not been monetized. Utilities and others would know in advance that this is the threshold, and could plan programs accordingly. With regulatory judgment, there would not be a pre-determined benchmark. Instead, the regulators would decide whether an efficiency program is cost-effective based on the available evidence regarding those impacts (e.g., tons of CO_2 avoided, number of job-years created) for that program.

The primary advantage of this approach is that it provides regulators with a great deal of flexibility in accounting for DER impacts that have not been put into monetary or proxy terms. Conversely, the primary disadvantage of this approach is that it provides utilities and other stakeholders with less up-front guidance or certainty regarding the outcome of the BCA.

Consequently, New York regulators should establish protocols for whether and how they expect to consider non-monetary terms in screening distributed energy resources. For example, this approach might be limited to certain DER types (e.g., low-income energy efficiency programs) or certain DER impacts (e.g., job creation). Or this approach may be applied for a limited period of time, during which better methods to account for DER impacts can be developed.

4.4. Multi-Attribute Decision Analysis

Impacts that are monetized, quantified, or simply identified qualitatively can all be directly factored into decision-making through the use of multi-attribute decision analysis (MADA). MADA is used to compare a set of options using selection criteria that are difficult to quantify or monetize. For example, DER investments may help animate retail markets and spur innovation, although these impacts may be very difficult to accurately quantify and monetize.

To compare alternatives, MADA utilizes a decision matrix that summarizes the data available regarding each alternative's attributes, and weights each attribute according to its importance. A common method to develop appropriate attribute weightings is to group similar or less-important attributes, and then to rank the attributes. From this ranking, weightings (summing to one) can be developed (Norris and Marshall 1995).

Data regarding a specific cost or benefit may be summarized in dollars (net present value), quantitatively (e.g., tons of emissions), or qualitatively (e.g., "high," "medium," or "low"). These data must then be normalized in order to achieve comparability, and qualitative measures converted into numerical values. In order to compare costs and benefits, a common technique prior to normalization is to invert the cost data (but not the benefit data). Costs and benefits can then be normalized by division by sum (dividing the values within each benefit category by the sum of the values) (Norris and Marshall 1995).

It is important to note that multi-attribute decision analyses must be designed and conducted very carefully to avoid inappropriate manipulation or unintended consequences.

The final step is to multiply each attribute's value by its weighting, and then calculate the overall score of the alternative by summing the individual weighted attribute scores (Norris and Marshall 1995).

The tables below illustrate how raw qualitative and quantitative data could be used, together with weightings, to calculate an overall score for various alternatives. Table 16 presents the "raw data" of net present values and qualitative scores in three other categories. If the monetized values alone were used, Alternative A would be the optimal investment, since its net present value is $1.54 million.

Table 16. Raw Data for Hypothetical Multi-attribute Decision Analysis

RAW DATA	Net Present Value of Monetized Costs and Benefits		Non-Monetized Environmental Benefits		Contribution to Market Animation		Non-Monetized Benefits to Participants	
	(Millions)	*Weight*	*(Qualitative Score)*	*Weight*	*(Qualitative Score)*	*Weight*	*(Qualitative Score)*	*Weight*
Alternative A	$1.54	0.60	Low (= 1)	0.20	Low (= 1)	0.15	Low (= 1)	0.05
Alternative B	$1.10	0.60	Medium (= 2)	0.20	Medium (= 2)	0.15	Low (= 1)	0.05
Alternative C	$0.87	0.60	High (= 3)	0.20	High (= 3)	0.15	Medium (= 2)	0.05

Once the data have been normalized and the qualitative information weighted and taken into account, the end result changes. Table 17 presents the normalized data (using division by sum), and the final scores. Using MADA, Alternative C is determined to be the optimal choice despite having the lowest NPV.

Table 17. Normalized Data and Overall Scores

NORMALIZED DATA	Net Present Value of Monetized Costs and Benefits		Non-Monetized Environmental Benefits		Contribution to Market Animation		Non-Monetized Benefits to Participants		Overall Score
	Normalized	*Weight*	*Normalized*	*Weight*	*Normalized*	*Weight*	*Normalized*	*Weight*	
Alternative A	$0.44	0.60	0.17	0.20	0.17	0.15	0.25	0.05	**0.33**
Alternative B	$0.31	0.60	0.33	0.20	0.33	0.15	0.25	0.05	**0.32**
Alternative C	$0.25	0.60	0.50	0.20	0.50	0.15	0.50	0.05	**0.35**

It is important to note that multi-attribute decision analyses must be designed and conducted very carefully to avoid inappropriate manipulation or unintended consequences. Regulators and other stakeholders must ensure that the analysis includes the proper criteria, uses weights that best reflect the intended value of the different criteria, uses an appropriate normalization technique, includes alternatives that are designed and modeled properly, and includes appropriate input values.

4.5. Summary

Direct monetization is the preferred approach to valuing benefits, and should be chosen whenever possible. However, if a cost or benefit cannot be readily monetized, it should be accounted for in another manner. Proxies generally represent the next best valuation option, as they allow a monetary value to be estimated for the benefit or cost. Additional benefits and costs that cannot be monetized directly or through use of a proxy can be accounted for through multi-attribute decision analysis.

Table 18 and Table 19 below present the primary valuation options for each DER benefit and cost: monetization, proxy, and MADA. A "yes" indicates the valuation option that generally represents the preferred method of accounting for the specific benefit, based on experience from other jurisdictions. However, the best valuation option depends upon data availability and may differ slightly for New York. In addition, the best valuation option can be expected to change over time.

As more data become available, more precise valuation methods can be applied. For example, a "yes" in the proxy column for participant property improvements indicates that there currently exists sufficient information to develop a proxy for that benefit. More precise data could be developed at a later date through detailed econometric studies, allowing the benefit to be directly monetized.

These tables are meant to illustrate the valuation options that New York could apply in the near term. The tables are based on general experience in other jurisdictions and should be modified as necessary through the current proceeding's stakeholder process. Ideally, over time and with better data, an increasing portion of the benefits and costs could be monetized, either directly or through proxies.

Table 18. Illustrative Benefit Valuation Options

Party Impacted	Benefits				Valuation Method		
		Benefit Category		Specific Benefits	Monetization	Proxy	Multi-Attribute
Utility Customers	1	Load Reduction & Avoided Energy Costs	a	Avoided energy generation	yes	---	---
			b	Avoided line losses	yes	---	---
			c	Wholesale energy market price suppression	yes	---	---
	2	Demand Reduction & Avoided Capacity Costs	a	Avoided generation capacity costs	yes	---	---
			b	Avoided power plant decommissioning	yes	---	---
			c	Wholesale capacity market price suppression	yes	---	---
			d	Avoided distribution system investment	yes	---	---
			e	Avoided transmission system investment	yes	---	---
	3	Avoided Compliance Costs	a	Avoided renewable energy and energy efficiency portfolio standard costs	yes	---	---
			b	Avoided environmental retrofits to fossil fuel generators	yes	---	---
	4	Avoided Ancillary Services	a	Scheduling, system control and dispatch	yes	---	---
			b	Reactive supply and voltage control	yes	---	---
			c	Regulation and frequency response	yes	---	---
			d	Energy imbalance	yes	---	---
			e	Operating reserve - spinning	yes	---	---
			f	Operating reserve - supplemental	yes	---	---
	5	Utility Operations	a	Financial and accounting	yes	---	---
			b	Customer service	yes	---	---
	6	Market Efficiency	a	Reduction of market power in wholesale electricity markets	---	---	yes
			b	Animation of retail market for DER products and services	---	---	yes
			c	Customer empowerment	---	---	yes
	7	Risk	a	Project risk	---	yes	---
			b	Portfolio risk	---	yes	---
			c	Resiliency	---	yes	---
Participants	8	Participant Non-Energy Benefits	a	Participant's utility savings (time addressing billing, disconnection, etc.)	---	yes	---
			b	Low-income-specific	---	yes	---
			c	Improved operations	---	yes	---
			d	Comfort	---	yes	---
			e	Health and safety	---	yes	---
			f	Tax credits to participant	---	yes	---
			g	Property improvements	---	yes	---
	9	Participant Resource Benefits	a	Other fuels savings	yes	---	---
			b	Water and sewer savings	yes	---	---
Society	10	Public Benefits	a	Economic development	---	---	yes
			b	Tax impacts from public buildings	yes	---	---
	11	Environmental Benefits	a	Avoided air emissions	yes	---	---
			b	Other natural resource impacts	---	---	yes

Table 19. Illustrative Cost Valuation Options

Party Impacted	Costs				Valuation Method		
	Cost Category		Specific Costs		Monetization	Proxy	Multi-Attribute
Utility Customers	1	Program Administration Costs	a	Program / project administration	yes	---	---
			b	Program / project marketing	yes	---	---
			c	Program / project evaluation costs	yes	---	---
			d	Incentives to customers to offset incremental measure costs	yes	---	---
			e	Incentives to customers for taking action or changing behavior	yes	---	---
			f	Capital costs	yes	---	---
	2	Utility System Costs	a	Increased energy consumption	yes	---	---
			b	Environmental compliance costs	yes	---	---
			c	Integration costs - distribution system	yes	---	---
			d	Integration costs - transmission system	yes	---	---
			e	Integration costs - ancillary services	yes	---	---
	3	DSP Costs	a	Platform costs - advanced distribution system management, capital, and operating expenses	yes	---	---
Participants	4	Participant Direct Costs	a	Capital costs (contribution to DER measures)	---	yes	---
			b	Transaction costs	---	yes	---
			c	Annual O&M costs	---	yes	---
	5	Other Participant Impacts	a	Increased heating or cooling costs	---	yes	---
			b	Value of lost service from curtailment	---	yes	---
			c	Reduced comfort	---	yes	---
Society	6	Public Costs	a	State tax credits	yes	---	---
			b	Federal tax credits	yes	---	---
	7	Health and Environmental	a	Health and Environmental	yes	---	---

5. ACCOUNTING FOR RISK IN THE BCA FRAMEWORK

5.1. Summary

There are risks associated with many aspects of electric utility system planning and operations, and it is important that they be properly accounted for in the BCA framework. The issue of risk is addressed separately in this chapter because it can cut across several of the issues raised in the other chapters of this report, and can have significant implications for the BCA framework.

Distributed energy resources generally result in reduced risk to the electricity system, relative to traditional supply-side resources. DERs can increase the diversity of the portfolio of electricity resources, reduce reliance upon fossil fuels with volatile prices, reduce planning risk by reducing load growth, reduce risks associated with current and future environmental regulations, and reduce risks associated with outages caused be storms and other unexpected events. Distributed energy resources also help to reduce risk through increased optionality and system resiliency. That is, through their distributed and small-scale nature, DER investments offer greater flexibility in helping the system cope with stress and respond to unanticipated changes in the future (relative to large, capital-intensive generation, transmission or distribution upgrades).

Risk can be accounted for in the DER BCA framework using a variety of different techniques, including: sensitivity analyses, scenario analyses, probability analyses, risk proxies, and the choice of discount rate. Accounting for risk through the choice of discount rate requires considering risk as one of several factors that might influence the choice of discount rate. The relationship between risk and the choice of discount rate is addressed further in Chapter 6.

Some of the risk assessment techniques listed above can be used in combination. For example, a portion of risk could be accounted for through a risk proxy, while the remaining portion of risk could be accounted for through the choice of a discount rate. Either way, risk should be accounted for in the BCA framework in a way that is transparent, does not understate risk impacts, and does not double-count or overstate risk impacts.

Risk can be accounted for in the DER BCA framework using a variety of different techniques, including: sensitivity analyses, scenario analyses, probability analyses, risk proxies, and the choice of discount rate.

The questions of which risk assessment techniques should be used in the DER BCA framework—and how—should be addressed once the BCA framework is more fully developed, when the risk analyses can be applied to specific types of costs and benefits. The key points to make at this time are:

- The risk impacts of DERs should not be ignored because they are difficult to assess;
- There are a variety of risk assessment techniques that can be used for this purpose; and
- Accounting for risk impacts can be inter-related with the choice of discount rates.

5.2. Background on Risk

Risk can be defined as the "potential harm from a future event that can occur with some degree of probability" (Ceres 2012, 6).[23] Thus, there are two components to risk: a probability of an outcome, and the magnitude of the harm from that outcome.

There is often a tradeoff between cost and risk. For example, electric system reliability risks can be reduced by building "excess" power plants or transmission lines, but this reduction in risk comes with higher costs. Both the probability of the outcome and the magnitude of the harm of the outcome should be considered:

- If both the probability and the magnitude of harm are low, then the risk could be considered small and may not warrant any cost to mitigate.
- If the probability of an outcome is high but the magnitude of harm is low, the risk could be considered small and may not warrant much cost to mitigate.
- If the probability of an outcome is low, but the magnitude of harm is high, then the risk could be considered significant enough to warrant mitigation.[24]
- If both the probability and the magnitude of harm are high, then the risk could be considered to be high and may warrant significant cost to mitigate.

There are a variety of different types of risks related to electricity system planning. Some key risks include, for example: system reliability and generation adequacy; grid reliability due to weather, storms and unexpected outages; fuel price volatility; load uncertainty; market risk; technology evolution and obsolescence risk; siting and costs of new transmission risk; siting and costs of new power plant risk; existing power plant operational risk; environmental regulation risk; economic and demographic swings; utility financial risk; and regulatory risk.

Project versus Portfolio Risk

It is useful to distinguish between project risk and portfolio risk. In the context of electricity system planning, project risk is based on the risks associated with a specific electricity resource, or even a specific program (e.g., an energy efficiency program, a distributed generation technology or program, a new coal plant, a new gas plant, a new wind facility).

All types of electricity resources have some level of project risk. When developing a BCA framework, it is important to account for the project risks associated with both the proposed resources and the avoided resources. In the context of the REV BCA framework, the proposed resources will be energy efficiency,

---

[23] Economists frequently distinguish between risk (when probabilities are known) and uncertainty (when probabilities are unknown). Colloquially, risk and uncertainty are often used nearly synonymously. Most of the discussion of risk here follows the economists' interpretation, assuming known probabilities of harmful outcomes.

[24] Fire insurance is an example of where many people pay to offset a risk that has very low probability of occurrence but a very high magnitude of harm.

demand response, distributed generation, and distributed storage options. The avoided resources can be classified as reduced purchases from the wholesale electricity markets, reduced transmission and distribution needs, reduced environmental impacts, and more.

Portfolio risk is based on the risks associated with the combination of resources that make up the entire electricity system. For example, a utility system that relies upon a variety of different types of fuels will have a lower portfolio risk (with regard to fuel prices) than one that relies primarily on one or two fuel types. Counterintuitively, some resources that have a high project risk can reduce portfolio risk by providing diversity and hedging the overall portfolio.

Who Experiences the Risk?

Electricity system risks (both project and portfolio) have different implications for different stakeholders. These stakeholders include utility shareholders, utility management, utility customers, power plant developers, DER vendors, customers installing DER, and society in general. In determining how to account for risk in a BCA framework, it is important to consider which stakeholder(s) will be affected by the risk, and by how much.

Sometimes risks are shifted between different stakeholders. For example, when the wholesale electricity market was established in New York, much of the risk of financing, constructing, and operating power plants was shifted from utility customers (and possibly utility shareholders) to private power plant developers. Risks can sometimes be shifted between utility shareholders and utility customers, depending upon the ratemaking practices used to recover utility investments.

This concept of shifting risk may be an important consideration in the context of promoting and developing the market for DERs in New York. If the distribution utilities play the primary role in promoting DERs, then the project risks associated with those new resources will primarily fall on utility customers (and possibly utility shareholders), and the customers that install DERs. Conversely, if unregulated DER vendors play the primary role in deploying DERs, then the project risks associated with those resources will primarily fall on DER vendors and the customers that install DERs.

5.3. Accounting for Risk in DER Benefit-Cost Analyses

Energy Policy Goals

The ultimate goal of the BCA framework is to identify which distributed energy resources, or combination of resources, will best meet New York's energy policy goals. Therefore, the BCA framework should account for risk in a way that is consistent with those goals.[25] For example, if the state's energy policy goals place a high value on avoiding the risks associated with volatile fossil fuel prices, then those risks should receive commensurate priority in the benefit-cost analysis.

[25] See the discussion in Chapter 2 regarding the energy policy goals relevant to DER in the context of the REV process.

In addition, when accounting for risk in the DER BCA framework, it is important to account for the risks to each of the three types of stakeholders discussed above: utility customers, participants, and society in general. These are the stakeholders that regulators are charged with protecting, in light of the state's energy policy goals. Power plant owners and DER vendors are unregulated actors participating in competitive markets, and therefore are responsible for taking their own actions to mitigate risk. Utility shareholder risk is primarily of a financial nature, and they have different options for mitigating risk (e.g., diversifying their financial portfolios). [26]

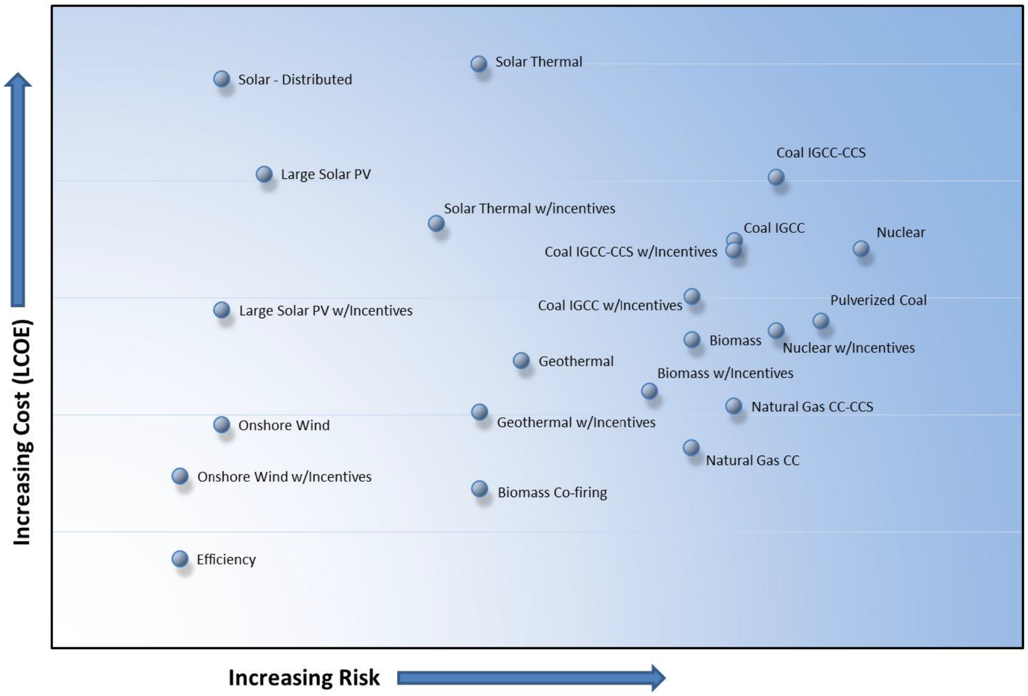
Project Risk

Different types of distributed energy resources may have different magnitudes of project risk. For example, energy efficiency resources may have some project risk associated with customer adoption rates, technology performance, or persistence of savings; demand response resources may have project risk associated with customer response; and distributed generation resources may have project risk associated with system integration or technology performance. These DER project risks can be reduced over time with experience in program design and implementation.

Figure 2 presents a summary of the range of risks associated with a variety of different electricity resources. Risk is shown to increase from left to right, while costs are shown increasing on the vertical axis. Resources in the lower-left quadrant have both less cost and less risk, while resources in the upper right have both high cost and high risk. DER project risks should be compared with the project risks associated with the resources that they are avoiding. These project risks must also be considered in the context of the portfolio risks that are reduced (or increased) with their introduction to the utility system, as discussed below.

[26] This is not to suggest that the risks to other stakeholders should be ignored, just that the risks to customers should be of paramount concern to regulators.

Figure 2. Relative Costs and Risks of a Variety of Electricity Resources



Source: Binz and Mullen 2012

Portfolio Risk

The treatment of risk in the BCA framework should focus primarily on portfolio risk, for several reasons. First, project risk can be mitigated by combining several different types of projects into the total portfolio. Second, many of the significant risks in the electricity industry are portfolio risks, e.g., reliability risk; fuel price risk; market risk; transmission risk; and environmental risk.

It is important to note that competitive markets do little to help mitigate portfolio risk. Each project developer in a competitive market works to mitigate his or her own risk, but does not have the incentive to take steps to mitigate portfolio risk for the electric system as a whole. The wholesale electric markets in New York and New England provide evidence of this. Most developers have added natural gas power plants to both systems very effectively, because these appear to be most profitable under current and expected market conditions. But on a portfolio basis, each new gas plant serves to increase system risk to an already heavily gas-dependent grid.

Similarly, investments in new central-station power plants increase reliance on the central grid. In contrast, investments in distributed resources, particularly distributed generation and distributed storage, help to protect resource owners against outages or recover more quickly. The value of this resilience is likely to increase as major disruptions associated with climate change become more frequent.

The extent to which any one type of resource will reduce (or increase) portfolio risk will depend upon how that type of resource compares with the current and future mix of resources in the portfolio. For example, adding another natural gas power plant to the New York wholesale electricity market will not help to reduce portfolio risk, and may actually increase it. On the other hand, distributed energy resources currently play a relatively small role in the New York electricity system, and can be assumed to help reduce portfolio risk through increasing portfolio diversity and helping to preserve options for future investments.[27] This may be especially true for reliability risk, fuel price risk, market risk, transmission risk, and environmental risk.

Risk Assessment Techniques

A variety of options are available to assess the risks associated with electricity resources. Although a comprehensive treatment of this topic is beyond the scope of this report, several options that could be implemented in New York in the near- to mid-term future are summarized below.[28]

The DER BCA framework in New York will presumably include a stream of future costs associated with DER compared with a stream of future avoided costs. Risk can be accounted for by making adjustments to the stream of DER costs, the stream of avoided costs, or both, using any of the following methods:

1) Sensitivity analyses can be used to indicate the extent to which specific risks will affect the costs of a specific portfolio mix. For example, the base case assumption for a particular risk factor (e.g., fuel prices) could be modified to estimate how a different fuel price affects the long-term costs of a specific resource mix. The results will provide an indication of the potential magnitude of the risk (in terms of cumulative present value dollars) associated with that one risk factor.

2) Scenario analyses can be used to indicate the extent to which different risk factors might affect future costs under different resource portfolios. For example, several different future scenarios may be developed based on different risk factors (e.g., high and low fuel prices, high and low load growth, and high and low environmental compliance costs). The costs of the different scenarios can help indicate the magnitude of the risks (in terms of cumulative present value) associated with the different risk factors under different resource portfolios.

3) Probability analyses can be used to determine the "expected value" of costs of resource portfolios with different assumptions about volatile factors. This approach applies assumptions regarding the probabilities associated with certain risk factors (e.g., the low fuel price case has a probability of 25%, the base case fuel price has a probability of 50%, and the high case fuel price has a probability of 25%). These probabilities are then multiplied by the forecasted costs associated with each case to determine an expected value of the costs of each scenario (in terms of cumulative present value dollars). This technique provides much more information relative to sensitivity and scenario analyses, because it accounts for both the likelihood of risky outcomes as well as the magnitude of the risky outcomes.

---

[27] Optionality represents the value of preserving the flexibility to change course later, as more information becomes available or circumstances change. Through representing smaller incremental investments, distributed energy resources offer greater flexibility than large, capital-intensive power plants (Liebreich 2013).

[28] For additional information, see NARUC's Energy Risk Lab at www.naruc.org.

4) Risk proxies can be used to approximate the impact of risk associated with new resources. For example, if distributed energy resources are assumed to offer a benefit in terms of reduced portfolio risk, then this benefit can be accounted for by applying a proxy multiplier to the DER benefits (i.e., the avoided costs). As an example, the Vermont Public Service Board requires that the risk benefits of energy efficiency be accounted for by applying a 10 percent risk proxy multiplier to the avoided costs used to screen energy efficiency resources (VT PSB 1990). The primary advantage of this approach is that it is simple to apply, and it explicitly acknowledges that there is a risk benefit associated with certain resources, even if those benefits are difficult to monetize. The primary disadvantage of this approach is that it may not be particularly accurate. (See Chapter 4 for a more complete discussion of how proxies can be used to account for impacts that are difficult to quantify and monetize.)

5) Discount rates can be adjusted to account for risk. Discount rates are used to account for the time preference applied to future BCA costs and benefits, and risk is one of the factors to consider in determining that time preference. This issue is addressed further in Chapter 6.

Some of the techniques above can be used in combination, as long as the method is transparent, does not understate risk impacts, and does not double-count or overstate risk impacts.

The different techniques to account for risk will have different implications for the costs and benefits of DERs. For example, a risk proxy multiplier will increase avoided costs by a constant amount in each year, while an adjustment to discount rates will have an increasingly larger effect on costs over time, due to the compounding nature of discount rates. For those risks that are expected to increase with time (e.g., risks associated with climate change), an adjustment to discount rates may more accurately capture this impact than a risk proxy multiplier.

6. Discount Rates

6.1. Summary and Recommendations

The choice of a discount rate for the DER BCA framework is not a formulaic, simple decision. The choice of discount rate is essentially a decision about time preference, i.e., the relative importance of short- versus long-term costs and benefits.

New York utilities currently use a discount rate based upon a utility's weighted average cost of capital when evaluating the cost-effectiveness of energy efficiency resources. The value of the current discount rate is 5.5 percent real. This is a relatively high discount rate, compared with the other options discussed in this chapter, and therefore places relatively less value on the long-term costs and benefits of energy efficiency resources. We recommend that this practice not be used as a precedent for the discount rate in the DER BCA framework, for reasons discussed below.

The purpose of the DER BCA framework is to identify those distributed energy resources that will meet the Commission's DER goals. The discount rate chosen for the DER BCA framework must reflect a time preference that is consistent with this set of regulatory goals.

The time preference used by a regulated utility for evaluating the costs and benefits of resource options can be very different from the time preference used by investors for evaluating their investment options. Regulated utilities have a variety of different goals and responsibilities to consider when planning their system (e.g., reducing system costs, increasing system efficiency, maintaining reliability, maintaining customer equity, maximizing profits for shareholders, mitigating risks to customers, and achieving other energy policy goals as required by the state). Individual investors have a different set of goals when making financial decisions (e.g., balancing risks and rewards, maximizing profits, maximizing short-term versus long-term returns). Consequently, the utility investors' time preference, as indicated by the utility weighted average cost of capital, is not necessarily appropriate for setting the discount rate for the DER BCA framework.

The purpose of the DER BCA framework is to identify those distributed energy resources that will meet the Commission's regulatory goals, including: reduce electricity costs, increase electricity system efficiency, maintain reliability, reduce risk, and achieve the other energy policy goals articulated by the Commission, both in the short-term and the long-term future. The discount rate chosen for the DER BCA framework must reflect a time preference that is consistent with this set of regulatory goals. The time preference indicated by the utility weighted average cost of capital is not consistent with this set of regulatory goals, and therefore will not lead to resource decisions that are consistent with this set of goals.

We recommend that the DER BCA framework use a societal discount rate. The societal discount rate is best able to reflect the value of short- versus long-term costs and benefits to all utility customers, as well as to society in general. The societal discount rate is best able to reflect the time preference associated with the state's energy policy goals, many of which are related to societal impacts.

We also recommend that the societal discount rate chosen for the DER BCA framework be somewhere in the range of zero to three percent real. This range is frequently used for societal discount rates, and is also very close to the current value of risk-free discount rates.

Additional factors, particularly risk, should be considered in choosing, within this range, the exact discount rate for the DER BCA framework. To the extent that risk has been evaluated and accounted for through other methods described in Chapter 5, a discount rate at the high end of the range of societal discount rates should be chosen. If risk has not been adequately evaluated and accounted for through other methods, a discount rate at the low end of the range should be chosen.

6.2. Background on Discount Rates

Accounting for Inflation

Projections of costs and benefits can be expressed in either of two ways: (a) in "nominal" or "current dollar" terms, unadjusted for inflation; or (b) in "real" or "constant dollar" terms, adjusted to remove the effects of inflation. Similarly, discount rates can be expressed in nominal (unadjusted for inflation) or real terms (with the effects of inflation removed). Either approach can be used to tell the same story, as long as it is used consistently throughout a document or analysis. Economists tend to prefer using real costs and, therefore, real discount rates.

In general, we recommend expressing all costs in real terms throughout the BCA framework, and then using a discount rate expressed in real terms for consistency. This approach (relative to putting everything in nominal terms) simplifies the analysis, ensures consistency, and indicates how costs will change over time independently of inflationary effects.

Further, expressing discount rates in real terms makes it easier to determine the appropriate time preference for costs and benefits. Removing the effects of inflation from the analysis and the discount rate helps to simplify the consideration of how much weight to give to current costs and benefits versus future costs and benefits.

Commonly-Used Types of Discount Rates for Efficiency Screening

Several discount rates are frequently used in energy efficiency BCA practices. Table 20 presents a range of typical values for these different types of discount rates.

- Societal discount rates reflect the tradeoff between short- and long-term costs and benefits to society as a whole associated with the investment or project.
- Risk-free discount rates reflect the tradeoff between short- and long-term costs and benefits under the assumption that there is little to no risk associated with the investment or project.
- Risk-adjusted discount rates reflect the level of risk associated with a specific investment or project, or a group of investments. Risk-adjusted rates are calculated by starting with a risk-free rate and then adjusting, usually upward, to reflect the risk of the investment(s) in question.

- The utility's weighted average cost of capital (WACC) is equal to what the utility has to pay investors when it raises new funds to support capital projects, averaged across both equity and debt. In effect, the WACC is an example of a risk-adjusted rate, based on the financial markets' estimate of the utility's average level of risk.
- Participant discount rates reflect the tradeoff between short- and long-term costs and benefits to program participants (i.e., customers adopting DERs). These rates represent the customer's time preference of money in general, not just with regard to energy costs and benefits.

Table 20. Ranges of Values for Real Discount Rates in Recent Years

Type of Discount Rate	Typical Range of Values (real)
Societal	0% - 3%
Risk-Free	1% - 3%
Risk-Adjusted	1% - 7%
Weighted Average Cost of Capital	5% - 7%
Participant	Varies widely by customer

Table 21 below presents the discount rates recently used by select states in New England and the Mid-Atlantic regions for energy efficiency benefit-cost analysis. It includes both the real discount rates used in the states, and the states' rationale for choosing the discount rates. The table also indicates the primary test used by the state for its BCA.

As the table shows, the discount rates used by states vary by rationale, by BCA test, and in magnitude. Some states use the same rationale to develop a discount rate (e.g., based on 10-year US Treasury bonds), but come up with different values.[29] The discount rates also vary widely within a specific BCA test (e.g., from 0.55 percent to 5.50 percent within the TRC test). Across states, rationales, and tests, the discount rates range considerably from 0.55 percent to 7.43 percent.

Table 21. State Discount Rates Used in Energy Efficiency Benefit-Cost Analysis

	Primary Test							
	UCT	Total Resource Cost Test					Societal Cost Test	
	CT	NY	NH	RI	MA	DE	VT	DC
Basis for Discount Rate	Utility WACC	Utility WACC	Prime Rate	Low-Risk 10 yr Treasury	Low-Risk 10 yr Treasury	Societal Treasury Rate	Societal	Societal 10 yr Treasury
Current Discount Rate (Real)	7.43%	5.50%	2.46%	1.15%	0.55%	TBD	3.00%	1.87%

[29] Presumably these different discount rates based on 10-year US Treasury Bonds were calculated using different time periods to come up with such different values.

The choice of discount rate has significant implications for the value of future costs and benefits, which will significantly affect the BCA results. Figure 3 illustrates how energy efficiency benefits are affected by the different discount rates used by each state. This example starts with a generic, illustrative stream of avoided costs (i.e., energy efficiency benefits) over the course of a 20-year period. The top, blue line indicates the magnitude of the future avoided costs assuming no real discount rate at all. We assume, for illustrative purposes only, that the stream of avoided costs begins at $100/MWh in year 1, and then increases by 2 percent annually, reaching nearly $150/MWh annually by the twentieth year. The real growth in avoided costs indicated by this line is due to anticipated increases in costs beyond the effect of inflation. For example, real increases in gas prices of two percent per year would lead to real increases in future avoided costs like those depicted in the "no discount" line.

The discount rates for each state from Table 21 are individually applied to this generic stream of avoided costs to observe the impact of using the different discount rates. As the figure shows, lower discount rates result in significantly higher values of avoided costs.[30]

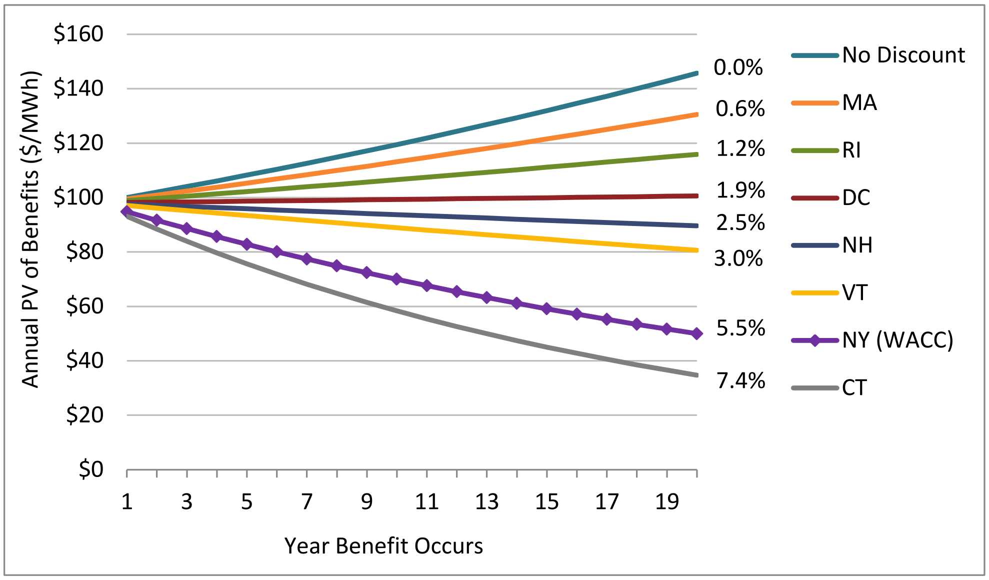
New York has historically used the utility WACC for a discount rate in the energy efficiency cost-effectiveness analyses. As indicated by the purple New York line, this assumption significantly reduces the monetary value of avoided costs in the later years. In year 10, the undiscounted avoided costs are on the order of $120/MWh, while the avoided costs discounted at the NY discount rate are on the order of $70/MWh. In year 20, the undiscounted avoided costs are on the order of $145/MWh, while the avoided costs discounted at the NY discount rate are on the order of $50/MWh.

The relatively high discount rate used in New York for efficiency screening implies that the state places relatively less value on future benefits relative to current benefits. In the context of the REV proceeding, this raises the question: What value doe the Commission want to place on future benefits relative to current benefits with regard to DER investments? This question is explored in the following section.

The choice of discount rate has significant implications for the results of the BCA analysis.

[30] While this analysis focuses on the discount rates used for energy efficiency programs, the discussion and key points can also be applied to other types of DER investments.

Figure 3. Implications of State Discount Rates Used in Benefit-Cost Analysis



6.3. Discount Rates for DER Benefit-Cost Analyses

Different Perspectives and Different Time Preferences

The choice of discount rate is essentially a decision about time preference, i.e., the relative importance of short- versus long-term costs and benefits. A high discount rate implies that short-term costs and benefits are valued more than long-term costs and benefits. In contrast, a low discount rate implies that short-term costs and benefits are valued similarly to long-term costs and benefits. The choice of discount rate is thus closely linked to who will be making the investment and experiencing the costs and benefits of that investment.

The purpose of the DER BCA framework is to identify those distributed energy resources that will meet a set of regulatory goals, including: reduce electricity costs, increase electricity system efficiency, maintain reliability, reduce risk, and achieve the other energy policy goals articulated by the Commission, both in the short-term and the long-term future. The discount rate chosen for the DER BCA framework must reflect a time preference that is consistent with New York energy policy goals, otherwise it is unlikely that the results of the DER BCA framework will achieve those goals.

The discount rate chosen for the DER BCA framework must reflect a time preference that is consistent with New York energy policy goals, otherwise it is unlikely that the results of the DER BCA framework will achieve those goals.

Despite the historical use of the utility WACC in evaluating the cost-effectiveness of energy efficiency resources in New York, we do not recommend that the utility WACC be used for the DER BCA framework. In sum, the time preference used by a regulated utility for evaluating the costs and benefits of different resource options can be very different from the time preference used by investors for evaluating their investment options.

To explain this point, we summarize below the time preferences of the different stakeholders potentially involved in DER decisions:

Utility investors: Investors that hold shares of utility stocks or bonds are interested in maximizing the return on their investments, in combination with the other investments in their financial portfolio. Their time preference for utility-related investments is reflected in the utility's cost of equity or cost of debt. The value that utility investors place on short- versus long-term costs and benefits is based on their goals when making financial decisions (e.g., balancing risks and rewards, maximizing profits, maximizing short-term versus long-term returns).

Utility management: Utility management has a range of responsibilities, including: developing electricity resources (both supply-side and demand-side) that will best serve their customers at just and reasonable rates, achieving state energy policy goals, and meeting its fiduciary responsibility to investors. The utility weighted average cost of capital is a good indication of management's time preference with regard to its investors, but it is not necessarily a good indication of the time preference associated with some of its other responsibilities as a regulated company.

Program participants: When deciding whether to participate in a DER program or install a DER measure, each customer must apply his or her time preference for short- versus long-term costs and benefits, based upon his or her own financial goals. Consequently, a participant's discount rate is relevant when applying the Participant Cost Test, which measures the net impacts over time on program participants. The results of the Participant Cost Test is also important in determining whether a program or technology is marketable and viable.

Individual utility customers: Individual electricity customers tend to have a wide range of time preferences, based upon their own financial goals. The value that a customer or group of customers places on short- versus long-term costs and benefits is based upon their personal financial goals.

All utility customers: The time preference of all utility customers as a whole (i.e., the utility system) should be based on goals defined by regulators, including: reduce electricity costs, increase electricity system efficiency, maintain reliability, reduce risk, and achieve the other energy policy goals, both in the short-term and the long-term future. The time preference for all utility customers is not a simple average of all customers' personal time preferences or discount rates.

Society: One of the interests of society is to help meet the needs of the present without compromising the ability of future generations to meet their needs.[31] Therefore, society has a broader tolerance for incurring costs in the short-term in order to experience benefits over the long-term. In addition, society, as represented by government agencies, is generally better able to access funds at a relatively low borrowing cost. Consequently, the societal discount rate tends to be lower than the discount rates of all of the parties listed above.

[31] Social security is one example. Environmental regulations are another example.

The Appropriate Time Preference for the DER BCA Framework

The discount rate chosen for the DER BCA framework must reflect a time preference that is consistent with state energy policy goals. As indicated in the list above, several of the key stakeholders have goals that are not completely aligned with state energy policy goals. Utility investors, utility management, program participants, and individual customers all have different goals and different time preferences.

However, there are two stakeholder groups – all utility customers and society – whose time preferences are very much aligned with state energy policy goals. Customer-funded DER programs are implemented for the benefit of all customers over the long term, in the same way that investments in supply-side resources are generally made to benefit all customers over the long-term. The DER programs are also implemented to achieve certain societal goals articulated by the Commission.

Therefore, the discount rate used for the DER BCA framework should represent the time preferences of all utility customers and society. Regulators are in the best position to determine such a time preference, as they are not driven solely by shareholder interests, nor are they driven solely by customer interests. Instead, they are in charge of representing the public interest, which requires accounting for many different factors, and sometimes making tradeoffs between conflicting factors, including tradeoffs between the value of current versus future costs.

The discount rate used for the DER BCA framework should represent the time preferences of all utility customers and society.

A societal time preference can be represented by applying a societal discount rate. As noted above, there are many factors that can go into a societal discount rate, and such rates tend to be in the range of zero to three percent real.

The time preference for all customers as a whole is not so easily defined. In determining such a time preference, regulators should consider what value they want to place on short- versus long-term costs and benefits. How much value do they place on receiving benefits today versus benefits in the future? How important are certain long-term energy policy goals (e.g., enhanced customer empowerment, market animation, resource diversity, reliability and resiliency), and how much value should be placed on achieving those goals in the future?

Furthermore, in determining the time preference for all customers as a whole, regulators should consider whether and how to account for risk in choosing the discount rate. This issue is discussed in the following subsection.

For the purpose of energy efficiency screening, it is sometimes recommended that the choice of discount rate be driven by the choice of screening test. In other words, the costs and benefits of the Utility Cost test should be discounted using the utility WACC, the costs and benefits of the Societal Cost test should be discounted using a societal discount rate, etc. However, the choice of discount rate does not need to be linked to the choice of test used to screen distributed energy resources. Discount rates represent the relative importance of short- versus long-term costs and benefits. Accounting for the tradeoffs between the short- and long-term impacts requires consideration of many different perspectives (especially all utility customers) and many factors, as described above.

Accounting for Risk in the Choice of Discount Rate

As described in Chapter 5, risk can be accounted for in a DER BCA framework with several different methods, including through the choice of discount rates. If risk has not been fully accounted for through alternative methods such as probability assessments or risk proxies, then it should be accounted for in the choice of discount rate.

One option is to choose a risk-free discount rate, to the extent that DER resources are determined to be risk-free or low-risk relative to the supply-side resources that are avoided. Risk-free rates can be represented, for example, by the long-term average rate on 10-year US Treasury bonds. From 1994 through 2013, the average real rate of return on 10-year Treasury bonds was 2.3 percent. Current rates are lower due to Federal Reserve monetary policies adopted to combat recession. For the year 2013, the real rate of return was 0.9 percent on 10-year Treasury bonds.[32]

Another option is to develop a risk-adjusted discount rate. This can be achieved by starting from a risk-free rate and adjusting upward for perceived risks of the project or portfolio. Unfortunately, there is no simple or automatic method of making risk adjustments to discount rates. These adjustments might require some judgment, based upon the risk considerations described in this report.

Another option is to choose a societal discount rate, to reflect a societal perspective on the risks associated with electricity resources. The societal discount rate is most likely to reflect the time preference associated with the state's energy policy goals, which have implications for society in general, as well as implications for utility customers.

Finally, regulators can choose a discount rate that is not necessarily bound by any of the definitions above, but is expected to best represent the time preference of the utility system as a whole, the time preference associated with state energy policies, and the time preference that leads to the mix distributed energy resources that is in the public interest. As indicated in Table 20 above, the societal discount rate and the risk-free discount rate both tend to be in the range of 0% to 3% real. Consequently, discount rates within this range reflect an appropriate time preference for the DER BCA analysis.

6.4. Recommendations

We recommend that the DER BCA framework use a societal discount rate. The societal discount rate is best able to reflect the value of short- versus long-term costs and benefits to all utility customers, as well as to society in general. The societal discount rate is best able to reflect the time preference associated with the state's energy policy goals, many of which are related to societal impacts. In

---

[32] Calculated from Federal Reserve data on nominal rates of return, available at http://www.federalreserve.gov/releases/h15/data.htm. Inflation rates (percentage increase in the Consumer Price Index) from the Bureau of Labor Statistics inflation calculator at http://data.bls.gov/cgi-bin/cpicalc.pl were subtracted to convert to real rates.

addition, the societal discount rate is consistent with the use of the Societal Cost Test, which we recommend using in the DER BCA framework (see Chapter 2).

We also recommend that the societal discount rate chosen for the DER BCA framework be somewhere in the range of zero to three percent real. This range is frequently used for societal discount rates, and is also very close to the current values of risk-free discount rates.

Additional factors, including risk, should be considered in deciding, within this range, the exact discount rate. To the extent that risk has been evaluated and accounted for through other methods described in Chapter 5, then the Commission should choose a discount rate at the high end of the range of societal discount rates. If risk has not been adequately evaluated and accounted for through other methods, then the Commission should choose a discount rate at the low end of that range.

As noted above, the Staff has proposed that the results of the Utility Cost Test, as well as the Societal Cost test, should be reported when evaluating the cost-effectiveness of DERs.[33] We recommend that the societal discount rate should be used when applying the Utility Cost test. The logic for doing so is the same as the logic described above for the Societal Cost Test. Namely, that the societal discount rate is best able to reflect the value of current versus future costs and benefits to all utility customers, as well as to society in general. This is true regardless of whether the scope of the test is defined broadly to include all of society, or the scope of the test is defined more narrowly to include only the costs to the utility system.

Finally, to the extent that the results of the Utility Cost Test are used to indicate the impact of DERs on average utility bills, as we recommend in Chapter 2, the Commission may want to apply a different discount rate for that purpose. In that analysis, the relevant question is: How much preference should be placed on bill reductions in the near-term versus bill reductions over the long-term? If long-term bill reductions are as important as short-term bill reductions, then it may be appropriate to use a lower discount rate relative to the rate used in the DER BCA framework, and vice versa.

---

[33] We do not address the results of the RIM Test here, because we recommend in Chapter 2 that they not be reported or used at all.

7. EXAMPLE TEMPLATES

Given the many different costs and benefits of distributed energy resources, as well as the different options for accounting for them, it would be useful to develop a set of templates to be used for the BCA framework. These templates would provide a systematic way to document all of the categories of costs and benefits included in the BCA framework, as well as the values of those categories determined in the analysis of a specific DER resource or set of resources. The templates below are examples of ones that could be used for the DER BCA in New York.

7.1. Screening Template

The table below presents an illustrative screening template to help systematize the process of accounting for costs and benefits. It includes one section for all of the monetized impacts and a separate section for the non-monetized impacts to indicate how each of them will be accounted for.

Table 22. Illustrative Screening Template

Monetized Impacts (Direct Monetization or Proxy Values)				
Perspective	**Benefits**	**Present Value**	**Costs**	**Present Value**
Utility Customers	Avoided Energy Costs	$ -	Program Administration, Marketing, Evaluation	$ -
	Avoided Line Losses	$ -	Incentives Paid to Participants	$ -
	Avoided Generation Capacity Costs	$ -	Capital Costs	$ -
	Avoided Decommissioning	$ -	Increased Energy Costs	$ -
	Wholesale Market Price Suppression	$ -	Increased Environmental Compliance Costs	$ -
	Avoided T&D Costs	$ -	Integration Costs - Distribution	$ -
	Avoided Environmental Compliance Costs	$ -	Integration Costs - Transmission	$ -
	Avoided Ancillary Services	$ -	Integration Costs - Ancillary Services	$ -
	Reduced Utility Operations Costs	$ -	Distribution System Platform Costs	$ -
	Proxy Value of Risk Benefits	$ -		
	Total Benefits to Utility Customers	**$ -**	**Total Costs to Utility Customers**	**$ -**
Participants	Other fuel savings	$ -	Capital Costs	$ -
	Water & Sewer	$ -	Annual O&M Costs	$ -
	Proxy Value of Non-energy benefits	$ -	Proxy Value of Transaction Costs	$ -
	Proxy Value of Non-energy benefits	$ -	Proxy Value of Non-Energy Costs	$ -
	Total Participant Benefits	**$ -**	**Total Participant Costs**	**$ -**
Society	Tax impacts from public buildings	$ -	Tax credits	$ -
	Total Societal Benefits	**$ -**	**Total Societal Costs**	**$ -**
TOTAL	**Total Monetized Benefits**	**$ -**	**Total Monetized Costs**	**$ -**
	Utility System Net Present Value:	$ -	**Utility System Benefit-Cost Ratio:**	
	Societal Net Present Value:	$ -	**Societal Benefit-Cost Ratio:**	
Non-Monetized Impacts				
Perspective	**Impact**		**Quantitative Values or Comments**	
Utility Customers	Contribution to Market Animation		e.g., program expected to promote market for rooftop PV	
Society	Economic development		e.g., job-years, or gross state product impacts	
	Reduced environmental impacts		e.g., impacts of CO_2 emissions not monetized above	
	Increased environmental impacts		e.g., increased CO_2 emissions from fossil generation from DR	

The monetized section includes a presentation of the results in terms of net benefits, presented in terms of cumulative net present value of revenue requirements. It also includes a presentation of the results in terms of a benefit-cost ratio, which is simply a ratio of the cumulative present values of benefits and costs.

The "monetized benefits" section also includes a separate presentation of the net benefits and benefit-cost ratio to the utility system (the Utility Cost Test) and to society (the Societal Cost test). This allows for consideration of the results in the context of both of the tests recommended by the Staff in its Straw Proposal.

However, the "non-monetized benefits" section of the template is a reminder that the monetized results should not be considered in isolation. The non-monetized results need to be accounted for somehow in order to ensure that the BCA framework fully accounts for all relevant costs and benefits. One of the best ways to do that would be through multi-attribute decision analysis.

7.2. Multi-Attribute Decision Analysis Template

As described in Chapter 4, multi-attribute decision analysis can be used to compare a set of options using selection criteria that are difficult to quantify or monetize. MADA can build off of the screening template above by directly accounting for the non-monetized impacts.

The screening template above identifies the following impacts that are not monetized: market efficiency benefits, economic development benefits, avoided environmental damages, and negative environmental impacts. These impacts are set up as separate decision-making criteria in the MADA template. Each of these would be given different weights, based upon the value that is placed upon them relative to the net present value of monetized costs and benefits.

Table 23. Multi-Attribute Decision Analysis Template

RAW DATA	**Net Present Value of Monetized Costs and Benefits**		**Market Animation**		**Economic Development**		**Reduced Environmental Impacts**		**Increased Environmental Impacts**		
	(Millions)	*Weight*	*Score*	*Weight*	*Score*	*Weight*	*Score*	*Weight*	*Score*	*Weight*	
Alternative A	$ -	0.__	_____	0.__	_____	0.__	_____	0.__	_____	0.__	
Alternative B	$ -	0.__	_____	0.__	_____	0.__	_____	0.__	_____	0.__	
Alternative C	$ -	0.__	_____	0.__	_____	0.__	_____	0.__	_____	0.__	
NORMALIZED DATA	**Net Present Value of Monetized Costs and Benefits**		**Market Animation**		**Economic Development**		**Reduced Environmental Impacts**		**Increased Environmental Impacts**		**Overall Score**
	Normalized	*Weight*	*Normalized*	*Weight*	*Normalized*	*Weight*	*Normalized*	*Weight*	*Normalized*	*Weight*	
Alternative A	$ -	0.__	_____	0.__	_____	0.__	_____	0.__	_____	0.__	____
Alternative B	$ -	0.__	_____	0.__	_____	0.__	_____	0.__	_____	0.__	____
Alternative C	$ -	0.__	_____	0.__	_____	0.__	_____	0.__	_____	0.__	____

The template could include a variety of rows to represent alternative resource options. Alternative A might be based on the avoided costs, while the other alternatives could include energy efficiency resources, demand response resources, distributed generation resources, or some combination of the above. These alternatives could then be directly compared with each other with this MADA template.

WORKS CITED

Binz, Ron, and Dan Mullen. 2012. "Electricity Policy: Risk-Aware Planning and a New Model for the Utility-Regulator Relationship." *Electrictiy Policy*. http://www.electricitypolicy.com/archives/4568-risk-aware-planning-and-a-new-model-for-the-utility-regulator-relationship.

Bird, L., J. McLaren, J. Heeter, C. Linvill, J. Shenot, R. Sedano, and J. Migden-Ostranter. 2013. *Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar*. NREL/TP-6A20-60613. National Renewable Energy Laboratory.

Black & Veatch. 2012. *Solar Photovoltaic (PV) Integration Cost Study*. Prepared for Arizona Public Service Company 174880.

CPUC. 2001. *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*. California Public Utilities Commission. http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF.

———. 2010. *Electric Energy Storage: An Assessment of Potential Barriers and Opportunities*. California Public Utilities Commission.

E3 and BPA. 2004. *Olympic Peninsula Study Of Non-Wires Solutions to the 500-kV Transmission Line from Olymbia to Shelton and a Transformer Addition at Shelton*. Energy and Environmental Economics, Inc. and the Bonneville Power Authority BPA Energy Efficiency Group & Transmission Business Line.

EPA. 2011. *The Benefits and Costs of the Clean Air Act from 1990 to 2020, Final Report - Rev. A*. U.S. Environmental Protection Agency Office of Air and Radiation.

———. 2013a. *Technical Support Document Estimating the Benefit per Ton of Reducing PM2.5 Precursors from 17 Sectors*. U.S. Environmental Protection Agency, Office of Air and Radiation, Office of Air Quality Planning and Standards. http://www.epa.gov/airquality/benmap/models/Source_Apportionment_BPT_TSD_1_31_13.pdf.

———. 2013b. "The Social Cost of Carbon." *EPA Climate Change Website*. http://www.epa.gov/climatechange/EPAactivities/economics/scc.html.

FERC. 1996. *(Order No. 888) Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*. *FERC Stats. & Regs. ¶ 31,036*.

FERC Staff. 2013. *Centralized Capacity Market Design Elements*. AD13-7-000. Federal Energy Regulatory Commission. http://www.ferc.gov/CalendarFiles/20130826142258-Staff%20Paper.pdf.

———. 2014. *Payment for Reactive Power*. AD14-7. Federal Energy Regulatory Commission. http://www.ferc.gov/legal/staff-reports/2014/04-11-14-reactive-power.pdf.

Fisher, Jeremy, Rachel Wilson, Nicole Hughes, Matthew Wittenstein, and Bruce Biewald. 2011. *Benefits of Beyond Business as Usual: Human, Social, and Environmental Damages Avoided through the Retirement of the US Coal Fleet*. Prepared for the Civil Society Institute by Synapse Energy Economics.

Freeman, Sullivan & Co. 2008. *Assessing Demand Response Cost-Effectiveness and Load Impacts in Ontario*. prepared for Ontario Power Authority.

Hall, Nick, and Jeff Riggert. 2002. *Beyond Energy Savings: A Review of the Non-Energy Benefits Estimated for Three Low-Income Programs*. Proceedings of the 2002 ACEEE Summer Study on Energy Efficiency in Buildings.

Hornby, Rick, Paul Chernick, David White, John Rosenkranz, Ron Denhardt, Elizabeth Stanton, Jason Gifford, et al. 2013. *Avoided Energy Supply Costs in New England: 2013 Report*. Synapse Energy Economics.

Interagency Working Group. 2013. *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*. Interagency Working Group on Social Cost of Carbon, United States Government. http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf.

Jakubiak, Ed, and Hawk Asgeirsson. 2003. "DG Comes to Detroit Edison." Presentation for Edison Electric Institute, April 8.

Keith, Geoff, Sarah Jackson, Alice Napoleon, Tyler Comings, and Jean Ann Ramey. 2012. *The Hidden Costs of Electricity: Comparing the Hidden Costs of Power Generation Fuels*. Prepared for the Civil Society Institute by Synapse Energy Economics. http://synapse-energy.com/sites/default/files/SynapseReport.2012-09.CSI_.Hidden-Costs.12-013.pdf.

Kingston, Tim, Therese Stovall, and John Kelly. *Exploring Distributed Energy Alternatives to Electrical Distribution Grid Expansion in Southern California Edison Service Territory*. ORNL/TM-2005/109. Distributed Energy Program Report. Gas Technology Institute.

Laws of New York. *State Energy Policy*. *Energy, Article 3, §3-101*. http://public.leginfo.state.ny.us/LAWSSEAF.cgi?QUERYTYPE=LAWS+&QUERYDATA=$$ENG3-101$$@TXENG03-101+&LIST=LAW+&BROWSER=BROWSER+&TOKEN=20570199+&TARGET=VIEW.

Lazar, Jim, and Xavier Baldwin. 2011. *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements*. Regulatory Assistance Project. www.raponline.org/document/download/id/4537.

Lazar, Jim, and Ken Colburn. 2013. *Recognizing the Full Value of Energy Efficiency: What's under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits*.

Liebreich, Michael. 2013. "The New Energy ROI: Reslience, Optionality, Intelligence." *Bloomberg New Energy Finance*, February 27. http://ceert.org/wp-content/uploads/PDFs/2013/BNEF_liebreich_the_new_energy_roi_resilience_optionality_intelligence.pdf.

Malone, Erin, Tim Woolf, Kenji Takahashi, and Spencer Fields. 2013. "Cost-Effectiveness Tests." In *Readying Michigan to Make Good Energy Decisions*. Synapse Energy Economics, Inc., Report to Council of Michigan Foundations.

Massachusetts Energy Efficiency Advisory Council. 2013. "Statewide Cost & Savings Tables (08-50 Tables)." *Year 2013 Results*. http://www.ma-eeac.org/Year%202013%20Results.html.

NARUC. 1992. *Electric Utility Cost Allocation Manual*. Washington, DC: National Association of Regulatory Utility Commissioners.

Neme, Chris, and Rich Sedano. 2012. *US Experience with Efficiency as a Transmission and Distribution System Resource*. Regulatory Assistance Project. www.raponline.org/document/download/id/4765.

NESP. 2014. *The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening*. The National Efficiency Screening Project. http://www.synapse-energy.com/Downloads/SynapseReport.2014-03.0.Resource-Value-Framework.14-027.pdf.

Norris, Gregory, and Harold Marshall. 1995. *Multiattribute Decision Analysis Method for Evaluating Buildings and Building Systems*. NISTIR 5663. Gaithersburg, MD: National Institute of Standards and Technology.

NPCC. 2010. "Chapter 5: Demand Response; Appendix H: Demand Response." In *Sixth Northwest Conservation and Electric Power Plan*. Northwest Power and Conservation Council.

NY DPS. 2014. “Mission Statement.” *New York State Public Service Commission*. http://www3.dps.ny.gov/W/PSCWeb.nsf/ArticlesByTitle/39108B0E4BEBAB3785257687006F3A6F?OpenDocument.

NY DPS Staff. 2007. *Staff Preliminary Proposal for Energy Efficiency Program Design and Delivery*. Case 07-M-0548. New York Department of Public Service.

———. 2011. *Energy Efficiency Portfolio Standard Program Review White Paper*. CASE 07-M-0548. New York Department of Public Service. http://www3.dps.ny.gov/W/PSCWeb.nsf/0/06F2FEE55575BD8A852576E4006F9AF7?OpenDocument.

———. 2014a. *Developing the REV Market in New York: DPS Staff Straw Proposal on Track One Issues*. New York Department of Public Service. Case 14-M-0101. August 22, 2014.

———. 2014b. *Reforming the Energy Vision DPS Staff Report and Proposal*. New York Department of Public Service. Case 14-M-0101. April 24, 2014.

NYISO. 2013a. *NYISO 2012 Annual Report on Demand Response Programs (Revised)*. New York Independent System Operator.

———. 2013b. *Manual 2, Ancillary Service Manual*. New York Independent System Operator. http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/ancserv.pdf.

———. 2014. New York Independent System Operator Website. *Ancillary Services*. http://www.nyiso.com/public/markets_operations/market_data/ancillary/index.jsp.

NY PSC. 2008. “Order Establishing Energy Efficiency Portfolio Standard and Approving Programs.” *New York Public Service Commission Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard* Case 07-M-0548: June 23, 2008.

———. 2011. “Order Authorizing Efficiency Programs, Revising Incentive Mechanism, and Establishing a Surcharge Schedule.” *New York Public Service Commission Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard* Case 07-M-0548: October 25, 2011.

———. 2013. “Order Approving EEPS Program Changes.” *New York Public Service Commission Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard* Case 07-M-0548: December 26, 2013.

NZ EECA. 2012. *Energy Wise: The Power to Choose. Multiple Benefits of Energy Efficiency*. New Zealand Energy Efficiency and Conservation Authority.

OEHHA/ALA. *Health Effects of Diesel Exhaust*. California Office of Environmental Health Hazard Assessment and the American Lung Association. http://oehha.ca.gov/public_info/facts/dieselfacts.html.

RMI. 2013. *A Review of Solar PV Benefit & Cost Studies, 2nd Edition*. Boulder, CO: Rocky Mountain Institute.

RMI, E3, and Freeman, Sullivan & Co. 2008. *Marshfield Pilot Design Report*. Sponsored by NSTAR Electric & Gas Corp. and the Massachusetts Technology Collaborative. Rocky Mountain Institute; Energy & Environmental Economics, Inc.; Freeman, Sullivan & Co.

Rodriguez, George. 2012. “SCE Experience with PV Integration, Presentation of Southern California Edison.” presented at the EPRI High Penetration PV Grid Integration Workshop, Tucson, Arizona, April 19. http://www1.eere.energy.gov/solar/pdfs/hpsp_grid_workshop_2012_rodriguez_sce.pdf.

SERA. 2010. *Non-Energy Benefits: Status, Findings, Next Steps, and Implications for Low-Income Program Analyses in California*. Prepared for Sempra Utilities, revised report. Skumatz Economic Research Associates, Inc.

Tetra Tech, Inc. 2011. *Massachusetts Program Administrators: Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation*. NMR Group, Inc.

———. 2012. *Massachusetts Program Administrators: Final Report - Commercial and Industrial Non-Energy Impacts Study*.

VT PSB. 1990. *Board Decision Adopting (as Modified) Hearing Officer's Report and Proposal for Decision*. Vermont Public Service Board. Docket 5270.

Whited, Melissa, Frank Ackerman, and Sarah Jackson. 2013. *Water Constraints on Electricity Production: Altering Our Current Collision Course*. Prepared for the Civil Society Institute by Synapse Energy Economics. http://synapse-energy.com/sites/default/files/SynapseReport.2013-06.CSI_.Water-Constraints.13-010.pdf.

Woolf, Tim. 2014. *Direct Testimony of Tim Woolf before the Florida Public Service Commission on the Topic of Setting Goals for Increasing the Efficiency of Energy Consumption and Increasing the Development of Demand-Side Renewable Energy Systems*. Docket No. 130199-EI. May 19, 2014.

Woolf, Tim, Erin Malone, Jenn Kallay, and Kenji Takahashi. 2013. *Energy Efficiency Cost-Effectiveness Screening in the Northeast and Mid-Atlantic States*. Prepared for Northeast Energy Efficiency Partnerships, Inc. Synapse Energy Economics.

Woolf, Tim, Erin Malone, Lisa Schwartz, and John Shenot. 2013. *A Framework for Evaluating the Cost-Effectiveness of Demand Response*. Prepared for the National Forum on the National Action Plan on Demand Response, Cost-effectiveness Working Group. Lawrence Berkeley National Laboratory. http://emp.lbl.gov/sites/all/files/napdr-cost-effectiveness.pdf.

Woolf, Tim, William Steinhurst, Erin Malone, and Kenji Takahashi. 2012. *Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for Other Program Impacts and Environmental Compliance Costs*. Prepared for the Regulatory Assistance Project. Synapse Energy Economics.

Zalcman, Fred, Kenji Takahashi, Geoff Keith, and William Steinhurst. 2006. *A Comprehensive Process Evaluation of Early Experience Under New York's Pilot Program for Integration of Distributed Generation in Utility System Planning*. NYSERDA 06-11. Pace Law School Energy Project and Synapse Energy Economics. Prepared for the New York State Energy Research and Development Authority.

APPENDIX A: GLOSSARY AND ACRONYMS

To the extent possible, the following definitions have been defined to be consistent with the definitions in the Staff's August 22 Straw Proposal.

- *Cost of environmental compliance*. Environmental compliance costs represent the direct costs that will be incurred by utilities and will eventually be passed on to ratepayers in order to comply with environmental regulations. Environmental compliance costs are part of the utility system costs, comparable to energy, capacity, transmission, and distribution costs.

- *Customers*. Residential, commercial, or industrial customers that procure electricity products or services in the DSP marketplace from their utility, an ESCO, DER provider, or other entity.

- *Demand Response (DR)*. A reduction in or shift in time of use of end-use customer consumption. Demand response programs employ a combination of price signals and automated technology (e.g. programmable, controllable thermostats) to reduce load during specific periods (daily or only in critical periods).

- *DER Customer*. Any end use/retail electric customer who employs distributed energy resources that are integrated with the DSP market.

- *DER Service Providers/Developers*. Providers of distributed energy products and services to retail customers, as well as an interface between end-use customers with DERs and the DSP.

- *Discount rate.* An interest rate applied to a stream of future costs and/or monetized benefits to convert those values to a common period, typically the current or near-term year, in order to reflect the time value of money. It is used in benefit-cost analysis to determine the economic merits of proceeding with the proposed project, and in cost-effectiveness analysis to compare the value of projects. The discount rate for any analysis is either a nominal discount rate or a real discount rate, with the real discount rate also accounting for inflation.

- *Distributed Energy Resource (DER)*. This term describes a variety of distributed resources, including end-use energy efficiency, demand response, distributed generation, and distributed storage. DERs are engaged at the low voltage, distribution level of the electric grid, either on the customer-side or utility side of the meter.

- *Distributed Generation (DG).* Any distributed energy resource that generates electricity. Examples include combined heat and power, photovoltaics, and small wind.

- *Distributed Storage (DS)*. A technology capable of storing previously-generated electric energy and releasing that energy at a later time. Storage technologies may store electrical energy as potential, kinetic, chemical, or thermal energy, and include various types of batteries, flywheels, electrochemical capacitors, compressed air storage, thermal storage devices, and pumped hydroelectric power.[34]

- *Distributed System Platform (DSP)*. DSP refers to both the institutional entity that creates and operates the distributed system platform, as well as the distributed system platform itself. The DSP is responsible for planning, designing, constructing, operating, and maintaining needed upgrades to existing distributions facilities. The DSP also fosters broad market activity by enabling active customer and third party engagement that is aligned with the wholesale market and bulk power system.

- *Distribution Utilities*. Distribution utilities construct, maintain, and operate distribution system infrastructure and assets. They also deliver electricity service to ESCOs and directly to end use residential, commercial and industrial customers. The Staff Straw Proposal considers distribution utilities and DSPs to be the same entities.

- *DSP Market Participant*. Any customer or DER service provider that directly interacts with the DSP. In many cases, DER service providers will aggregate DERs from multiple residential and small commercial customer to serve as an intermediary between customers and the DSP. In some cases, large commercial customers may interface directly with the DSP.

- *Energy Efficiency (EE)*. Products and services that reduce electricity consumption relative to baseline usage. Further, end-use customers can procure energy efficient products individually (e.g. via purchase of LED lights to replace incandescent) or through service offerings provided by DER providers.

- *Energy Service Company (ESCO)*. Provide commodity electric service to customers, delivered by distribution utilities. ESCOs may also be DER service providers. Per the Staff Straw Proposal, ESCOs will be encouraged to provide DER services.

- *Environmental externality*. Environmental externalities include the health and environmental impacts to society in general that are not internalized in the market price of a good or service. These are the impacts that remain, if any, after a utility has complied with relevant environmental regulations.

- *Framework*. A defined, systematic approach for accounting for and comparing costs and benefits.

- *Market Actors*. All entities that participate in New York electricity markets (both wholesale and retail), including those anticipated to participate in future DSP retail markets.

[34] California Public Utilities Commission Policy and Planning Division, "Electric Energy Storage: An Assessment of Potential Barriers and Opportunities," July 9, 2010. http://www.cpuc.ca.gov/NR/rdonlyres/71859AF5-2D26-4262-BF52-62DE85C0E942/0/CPUCStorageWhitePaper7910.pdf

- *Market Animation.* As envisioned in REV, market animation implies that customers will increasingly: 1) be aware of and adopt DER technologies and services; and 2) use DER technologies in such a manner as to optimize their value to the grid and to the customer.

- *Metrics*. Factors that provide an indication of the extent to which an outcome is achieved. These can be quantitative or qualitative, but should provide a reasonably objective means of assessing the magnitude of an outcome and allow comparisons to be made. For example, the number of hospital visits before and after a major project is implemented is a metric used to indicate the magnitude of health benefits.

- *Microgrids*. A group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid may be able to connect and disconnect from the grid to enable it to operate in both grid-connected or island mode.

- *Monetization*. Presenting a benefit in terms of a monetary value, i.e., in terms of dollars.

- *Nominal dollars*. Nominal or current dollars reflect anticipated inflation rates. In other words, nominal or current dollars are unadjusted for inflation.

- *Non-energy impacts*. Costs or benefits beyond those relating directly to energy, capacity, or ancillary services.

- *Present value dollars*. A future amount of money that has been discounted to reflect its current value, as if it existed today. For projects with multiple years of investments and benefits, the costs and benefits in each year of the future are typically presented in present value terms using a constant discount rate per year.

- *Quantification*. Presenting a benefit in numerical terms, regardless of the unit used to quantify (e.g., tons, job years, MWh, loss of load probability, etc.).

- *Real dollars*. Real or constant dollars are adjusted to remove the effects of inflation.

- *Risk*. There are three types of risks related to utility system resource planning: financial risk, project risk and portfolio risk.

    - *Financial risk*. This refers to the risk associated with the funding (i.e., the cost of capital) used to invest in a supply-side or demand-side resource.

    - *Project risk.* This refers to the risks associated with planning, constructing, and operating a resource or project. It involves the possibility that a technology or project will not perform as anticipated.

    - *Portfolio risk.* This refers to the risk experienced by an investor from the total portfolio of investments, projects, or resources. Different combinations of investments, projects, or resources will result in different types of risks for the investor. One common practice for reducing portfolio risk is to diversify investments.

- *Uncertainty*. The range or interval of doubt surrounding a measured or calculated value within which the true value is expected to fall with some degree of confidence. (NEEP 2011, p 30).

- *Valuation*. Accounting for the value of a benefit - either through market prices, monetization, quantification, the use of a proxy, or some other approach.

APPENDIX B: QUANTIFICATION AND MONETIZATION OF DER IMPACTS

Accounting for Benefits to All Utility Customers

As illustrated in Table 6, the primary categories of benefits to all utility customers are:

1. Load reduction and avoided energy costs
2. Demand reduction and avoided capacity costs
3. Avoided compliance costs,
4. Avoided ancillary services
5. Utility operational savings
6. Market efficiency
7. Risk

Load Reduction and Avoided Energy Costs

Quantification: The first step in calculating avoided energy costs is to identify the quantity of central generation avoided (kWh), and the timing of such generation. It is also important to identify the location of the distributed resource, as delivered energy costs vary by location due to transmission and distribution constraints. Quantification may be straight-forward for resources that have predictable generation profiles and meters to quantify such generation (e.g., separately-metered solar PV and baseload DERs such as fuel cells), while demand resources such as energy efficiency may require detailed impact evaluations and engineering studies.

Avoided line losses are quantified in terms of kWh, and are typically expressed as a percentage of generation. Typical utility-wide average annual line losses range from 6 percent to 11 percent, but these losses are not uniform throughout the day or year. Marginal losses may be twice as large as average losses, and therefore effort should be made to estimate the avoided line losses during the hours that distributed resources are operating (Lazar and Baldwin 2011).

Monetization: The value of avoided energy costs in New York can be estimated based on forecast energy market prices and market price suppression effects. The forecast values of energy include both short- and long-run components. These price forecasts should reflect temporally- and zonally-differentiated prices in order to capture the avoided energy prices for the time periods during which distributed energy resources are operating. These values are often calculated with the aid of an hourly dispatch model (Hornby et al. 2013).

Market price suppression impacts must be treated carefully. By providing energy at a lower cost, DER participation in the wholesale market can flatten the supply curve, resulting in the market clearing at a lower price.[35] Because wholesale energy markets provide a single clearing price to all wholesale customers purchasing power in the relevant time period and load zone, DERs can reduce the price of energy for all customers in the market for all units of energy purchased at that time. Some of the price suppression impact is effectively a transfer of wealth from producers to consumers, but a portion also represents a net social gain through the use of more efficient resources. The decision to include the entire price suppression effect or limit it to the net change in social welfare depends on the perspective taken in the benefit-cost analysis.

Demand Reduction and Avoided Capacity Costs

Quantification: Quantification of avoided capacity costs is similar to the process for estimating avoided energy costs. Avoided generation capacity (kW) is the quantity of distributed energy resource capacity that is expected to clear in the wholesale capacity market, or the capacity avoided by demand reductions that are not bid into the capacity market.

NYISO rules specify which resources are allowed to bid in the capacity auction and how such resources' capacity values are computed. The quantity of capacity avoided by energy efficiency may be derived through detailed impact evaluations and engineering studies, taking into account each resource's unique capabilities and expected performance. Projections of capacity needs are informed by load growth forecasts, retirements of existing capacity, addition of new capacity from resources to comply with RPS requirements, imports, exports, and new, non-RPS capacity additions (Hornby et al. 2013).

DERs may also avoid transmission and distribution capacity investments. T&D capacity avoided costs vary by location within utilities service territories, and the ability of DERs to avoid T&D capacity is dependent on the correlation of DERs with both local area non-coincident and system-wide coincident peak demand.

Monetization: The value of avoided generation capacity is based on forecast wholesale capacity market prices and market price suppression effects, calculated in a manner similar to avoided energy costs. However, the capacity value of distributed energy resources must also be "grossed up" to account for reserve requirements. This is typically accomplished by first increasing the wholesale market capacity

[35] DERs that do not participate directly in the market will also have some price suppression effect through reducing demand. However, this impact will be only a fraction of that which would be captured through direct participation in the wholesale market, particularly for capacity. This dilution of price suppression impacts occurs because the system operator typically performs an econometric analysis to forecast future capacity requirements. The data underlying the model are historical, and thus the coefficients for each variable are developed based on historical trends (after controlling for the influence of other variables.) Any increase in DERs in the current year will only slightly shift the trend line for the following year's forecast, and thus the impact of a change in DER participation will be watered down when translated to forecast system requirements. Only after five or ten years will the full value of the DER be recognized in the load forecast. In contrast, direct market participation allows the full impact of the DERs to be captured and appropriately valued.

price by the reserve margin requirements (a certain percentage), and then increased by a certain percentage to reflect avoided line losses (Hornby et al. 2013).

Over the short-run, while there is sufficient existing capacity resources on the system, wholesale capacity market prices are primarily driven by the mix of existing capacity resources. Over the long run, when new capacity is needed to meet demand, the capacity market prices are driven by the cost to construct a new peaking unit (e.g., a natural gas combustion turbine), net of what the unit would earn through participation in the energy and ancillary services markets (FERC Staff 2013). One of the challenges in estimating the impact of distributed energy resources on market prices is distinguishing between the short- and long-term market price impacts, and determining when the transition point between these impacts occurs.

Simulation models are frequently used to forecast auction clearing prices. These models take into account expected capacity resource retirements and additions, imports and exports, and load growth forecasts, as well as expected changes to market rules (Hornby et al. 2013). Much of this information is derived from data provided by system operators. For example, each year the New York Independent System Operator (NYISO) produces a report with ten-year forecasts of peak demand, proposed capacity resources, and proposed transmission facilities.[36] Such data inform projections of the slope of the supply curve and of system capacity needs.

Capacity market price suppression impacts are calculated in a manner akin to that for the energy market. Distributed energy resources that participate in the capacity market can flatten the supply curve, resulting in the market clearing at a lower price and reducing capacity costs for all customers. As in the energy market, only a portion of this price suppression results in a benefit to society, as much of the price impact is effectively a transfer of wealth from producers to consumers. To quantify the social welfare gain, the change in social welfare (defined as the sum of producer surplus and consumer surplus) before and after the participation of DERs should be estimated.

Distributed energy resources have the potential to defer or avoid significant T&D investments, while reducing the costs of maintaining existing T&D resources. The avoided cost can be constructed by estimating historical annual marginal T&D investment, or by evaluating planned, future T&D investment at specific sites. A common method for estimating avoided T&D costs is through “projected embedded analysis,” which uses long-term historical trends (more than 10 years) and sometimes planned T&D costs to estimate future avoided T&D costs (NARUC 1992).

Alternatively, the “system planning approach” examines relevant components of specific planned T&D projects, providing a more detailed local-area view of avoided T&D costs. Under the system planning approach, projected investment costs, system performance data, forecasted area load growth are used to develop estimates of avoided T&D costs for specific locations (NARUC 1992). The system planning

[36] In New York, these reports are commonly referred to as the “Gold Book.”

approach has been used by utilities in New York, [37] as well as Vermont, California, Massachusetts, and the Bonneville Power Authority (Zalcman et al. 2006; Jakubiak and Asgeirsson 2003; Kingston, Stovall, and Kelly; E3 and BPA 2004; RMI, E3, and Freeman, Sullivan & Co. 2008; Neme and Sedano 2012).

Avoided Compliance Costs

Quantification: The impacts on emissions from either curtailing, or increasing, electric load on the utility system will depend upon the specific power plants which are operating at the margin at the time of reduced or increased demand. For example, reducing demand during peak hours by shifting load to off-peak may reduce the emissions associated with natural gas peaker plants that are on the margin. Similarly, reducing demand via a permanent energy efficiency improvement or a baseload DER such as fuel cells will reduce emissions from the power plant on the margin.[38] The emissions from marginal power plants can vary significantly across regions, as well as during different times of the day, season, or year. In addition to shifting the timing of energy consumption, DERs, particularly storage, may lead to a net increase in energy consumption. Estimates of the environmental impacts of DERs should account for these important factors.[39]

Renewable distributed generation resources and energy efficiency may also help states comply with renewable portfolio standards (RPS) and energy efficiency portfolio standards (EEPS), thereby reducing the utility costs of compliance with the RPS and EEPS policies. New York currently has an RPS for customer-sited generation as well as large-scale generators,[40] and the state has an energy efficiency goal of reducing its electricity usage 15% by 2015.[41]

Monetization: In states with wholesale energy markets such as New York, the costs of pollution control or monitoring equipment, allowance costs, and pollution permits and fees will be reflected in energy market prices. To estimate how these costs will change in the future, energy cost projections should take into account forecasts of allowances, permits, and fees (e.g., RGGI allowances in the near term, and longer-term CO_2 price estimates for later years). If DERs contribute to the early retirement of a unit, thereby avoiding the capital and fixed O&M costs of environmental retrofits, these costs should be

---

[37] Recently, Consolidated Edison's planning identified an area of Brooklyn and Queens where rapid load growth would cause peak demand to exceed the capability of supply feeders. To address this load growth and implement a solution to cope with continued peak demands in the area, Con Edison filed a long-term plan to develop and implement distributed energy resources. Cases 13-E-0030, et al. (*Con Edison Electric, Gas and Steam Rates), Brownsville Load Area Plan*, August 21, 2014.

[38] However, shifting that load to off-peak hours may result in increased generation from a coal unit operating as the marginal unit during those off-peak hours. It is also possible that the operation of DERs, such as demand response that utilizes diesel or other back-up generators, could lead to a temporary increase in air emissions.

[39] As noted above, because there is some level of losses associated with the operation of a storage system, distributed storage results in a net increase in energy consumption. In addition, some demand response programs may result in increased energy consumption due to pre-cooling, or rebound effects that more than offset the load reduction.

[40] NYSERDA, *New York Renewable Portfolio Standard,* updated August 14, 2014, https://www.nyserda.ny.gov/Energy-Data-and-Prices-Planning-and-Policy/Program-Planning/Renewable-Portfolio-Standard.aspx

[41] New York State Public Service Commission, *07-M-0548: Energy Efficiency Portfolio Standard – Evaluation*, http://www3.dps.ny.gov/W/PSCWeb.nsf/All/766A83DCE56ECA35852576DA006D79A7?OpenDocument

included in the costs avoided by DERs (Lazar and Colburn 2013). The foregoing avoided costs address only the costs of complying with current environmental regulations. DERs may also avoid costs stemming from expected future environmental regulations, which may be in part captured through risk mitigation.

In order to estimate the value of avoided renewable resource obligations, the cost of a renewable energy certificate (REC) may be used. Customer-sited generation could also reduce the quantity of energy efficiency that must be provided, which can be estimated using the cost per kWh saved of New York energy efficiency programs.

Ancillary Services

Quantification: By reducing demand, customer-sited DERs may reduce the spinning and supplemental operating reserves that must be procured through the wholesale ancillary services market. Certain types of DERs can also provide ancillary services directly. For example, solar PV with an advanced inverter can inject or consume VARs to control voltage (RMI 2013). This voltage support service is compensated through NYISO at embedded cost-based prices, but may eventually be transacted at a more local level through the DSP. Other types of DERs, particularly demand response, may participate in the wholesale ancillary services market directly in order to provide reserves and other ancillary services when called upon. (Currently demand response may provide spinning reserves and regulation service or non-synchronized reserves in New York's wholesale ancillary services market) (NYISO 2013b). These ancillary services may also eventually be transacted through the DSP at the local level.

Monetization: The value of ancillary services provided through the wholesale market, including any market price suppression effects, can be estimated in a manner similar to capacity and energy values. Forecasts of ancillary service prices should take into account potential increases in reserves, regulation, and other services stemming from higher penetration of variable resources such as wind and solar.

Cost-based services, such as voltage support, are calculated as described in NYISO's ancillary services manual (NYISO 2013b). Voltage support payments are equal to the payment rate (currently $3,919/MVAr) multiplied by the resource's tested reactive power capacity, prorated by the number of hours that the resource provides voltage support resources (FERC Staff 2014).

Risk

Risk is discussed in detail in Chapter 5.

Utility Operations

Quantification: To quantify reductions in arrearages and late payments or customer service actions, utilities may undertake an evaluation study. Alternatively, these impacts may be estimated in the business case for smart grid proposals.

Monetization: Avoided costs can be estimated through incremental incidence (marginal valuation) estimates, billing and payment data analyses, or economic impact modeling tied to primary data collection or secondary data analysis. All electric utilities use a uniform system of accounts under which reduced arrearages and late payments or customer service actions fall.

Accounting for Costs to All Utility Customers

As illustrated in Table 7, costs to all utility customers can be grouped into the following primary categories:

1. Program administration costs
2. Utility system costs
3. Distributed System Platform costs

Program Administration Costs

Quantification: Program administration costs are typically quantified through recording direct labor hours, consultant and legal fees, office space and equipment (which may include specialized software or communications infrastructure), and the amount of incentives paid to participants or manufacturers.

Monetization: While program administration costs are typically readily monetized through wages and prices, care should be taken that only the incremental costs of the program are included in the framework. While the incremental costs may be obvious for some expenses, such as EM&V studies of programs, teasing out the specific DER costs for other activities, such as billing system upgrades, can be more challenging.

Utility System Costs

Quantification: Distributed energy resources have the potential to both increase and decrease electricity demand, as well as change the timing and variability of generation. These impacts can reduce the efficiency of thermal generators, as well as increase electricity related emissions, energy prices, and T&D costs. Generally, such cost impacts can be quantified using dispatch modeling, simulation modeling, investment cost estimates, and other methods as appropriate.

An hourly dispatch model may be used to quantify the impacts on system efficiency from distributed generation. Such models use the generating profiles of distributed generators to quantify the extent to which inflexible central steam-powered generators will be forced to operate at a less efficient (MWh/MMBtu) level of output. When this occurs, the cost impact will be reflected in the model's energy price.

As described in Chapter 3, distributed storage and demand response may increase net electricity consumption, impacting utility system costs. In addition, there may be an increase in emissions of CO_2 or criteria air pollutants depending on the properties of the generation operating during the different time periods. This increase in emissions may result in higher environmental compliance costs for the utility system.

Integration of distributed generation can also impose costs on the utility system through increasing the quantity of ancillary services required and, in some cases, by requiring distribution system upgrades. These costs are expected to be very small for low penetrations of DG, but would likely increase as penetration increases. The specific impact on reactive supply and voltage control, frequency regulation, energy imbalance, and operating reserves may be a net cost or a net benefit, depending on the specific generating profile and characteristics of the distribution network infrastructure where the generator is interconnected.

Generally, neither distributed generation nor distributed storage will increase transmission costs, as their power remains on the distribution grid, never stepping up to a transmission line. However, with very large penetration of DG or distributed storage in a small enough area, it is theoretically possible for the distribution grid to be upgraded to allow that energy to flow on the transmission system, potentially leading to transmission upgrades as well.[42] In practice, the quantity of DG permitted to interconnect on an individual feeder, or associated with an individual substation is limited, in part to prevent this phenomenon.

Quantification of T&D costs begins with identification of potential deviations from performance standards for distribution system components due to the integration of distributed generation. A commercially available distribution simulation model designed to represent the characteristics of the system's distribution feeders can be used to explore potential deviations from performance standards and loading limits of feeders.[43] In addition, other impacts not detected by the simulation model should be identified, where possible.

Monetization: The costs associated with decreased central station generator efficiency, increased energy consumption, and increased environmental compliance costs are monetized the same way avoided energy consumption and avoided environmental compliance costs are monetized, as described above.

T&D upgrades and other integration costs are location- and DER profile-specific; estimating their value with a high degree of certainty may require engineering studies. These costs can also vary significantly based on the penetration level of distributed resources, typically posing little cost to the system at low levels of penetration, but increasing costs as adoption expands.

The value for reserves and most other ancillary services is the price to procure these services through the NYISO ancillary services market. Forecasts of ancillary service prices should take into account potential increases in reserves, regulation, and other services stemming from higher penetration of variable resources such as wind and solar.

---

[42] For example, Black & Veatch note that "The heavy concentration of future distributed PV in one location (Phoenix) may impact transmission planning and integration costs due to limited geographic diversity for PV generation, especially in 2030" (Black & Veatch 2012).

[43] Options include Milsoft software model (http://milsoft.com/) and CYME (http://www.cyme.com/).

Cost-based services, such as voltage support, are calculated as described in NYISO's ancillary services manual (NYISO 2013b). Voltage support payments are equal to the payment rate (currently $3,919/MVAr) multiplied by the resource's tested reactive power capacity, prorated by the number of hours that the resource provides voltage support resources (FERC Staff 2014).

DSP Costs

Quantification: The DSP's responsibilities will include (1) provision of data to market actors, management of customer and third-party market participation, and facilitation of customer engagement; (2) monitoring and dispatch of DERs; and (3) distribution planning and construction. These costs can be quantified in terms of personnel costs, incremental data management and communications systems, additional modeling software, administrative and overhead costs, and other costs incurred by the DSP to perform its roles and responsibilities.

Monetization: DSP costs are expected to be monetized in a manner similar to costs of distribution utilities and recorded using a uniform system of accounts. Only those costs directly associated with distributed energy resources should be included in the benefit-cost analysis. The DSP role may initially be held by the distribution utilities, in which case it is even more critical to ensure that only the incremental costs associated with operating the distributed system platform are quantified, rather than including the utility's current operational and planning costs. Detailed record keeping will be required to properly account for these costs.

Accounting for Benefits to Participants

As illustrated in Table 7, participant-perspective impacts can be grouped into two primary categories:

1. Participant non-energy benefits
2. Participant resource benefits

These benefits may include avoided equipment O&M costs, avoided health and safety costs, avoided cost of moving, and increased property value.[44] Many of these impacts utilize similar quantification and monetization methods, and are therefore all addressed together in this section. Nevertheless, these impacts should be separately estimated to ensure that all benefits are addressed and to avoid double counting.

Quantification: Many participant impacts are intangible and therefore difficult to measure. Improved comfort, improved aesthetics, or a sense of doing good for the environment are frequently valued directly through non-market valuation techniques (discussed below), as opposed to first being quantified using a non-monetary unit.

[44] The primary benefit to participants is in terms of electric bill reductions. The primary benefit to other customers and to society is in terms of avoided costs. These benefits to participants are best evaluated through the participant cost test.

Others impacts are very tangible, such as improved health or increased property value, but can be difficult to quantify. These impacts may be derived entirely from secondary sources and computations, or from surveys. Surveys are frequently used for practical reasons, such as the lack of secondary data and the relative ease and low cost of including questions on surveys that are already being used to value intangible impacts. Econometric analyses are often used to quantify impacts due to energy efficiency programs or other distributed energy resources. These impacts may be measured in units such as:

- Retail sales (units sold)
- Industrial output (units produced)
- Employee sick days
- Hours addressing utility billing issues
- Number of participants receiving tax credits
- Time that real estate is on the market prior to being rented or sold (days)
- Equipment maintenance requests or repair time (number of requests or hours)
- Other fuel or water savings (gallons)
- Property values (tax assessment or real estate market value)

Monetization: Some participant impacts can be readily monetized following quantification using market prices. For example, improved health measured in reduced number of sick days can be multiplied by an assumed wage rate for the participant from secondary data. However, numerous other impacts must be monetized through non-market valuation techniques, such as: (a) contingent valuation (willingness to pay [WTP]), (b) relative valuation (RV), (c) conjoint analysis (CA), and (d) overall versus individual benefit values.[45]

One of the most direct methods of monetizing impacts on participants is through estimating the participant's willingness to pay. In this method, respondents are asked how much they would pay to obtain a benefit or a group of benefits. For example, to quantify the value of reduced noise in the home, respondents who reported that a program resulted in reduced noise would be asked, "How much would you be willing to pay to go from the previous noise level in your home to the present noise level, if everything else were the same?" A variant on this method is to ask respondents how much they would pay to get a group of benefits back if they disappeared.

The relative valuation method involves asking respondents the value of the impact relative to the bill savings from a program, either in terms of a verbally labeled scale (Labeled Magnitude Scaling) or in percentage or dollar terms (direct scaling or self-reported percentages). For example, an RV survey might ask respondents whether they have experienced changes in the noise level in their home as a result of the program, whether these changes are positive or negative, and whether the value of these

[45] For more information on these methods, see Tetra Tech 2011, chapter 5.

changes is higher than, lower than, or about the same as the bill savings from the program (or, for negative changes, how much the value detracts from the bill savings). A follow-up question would ask how much more or less than the bill savings, expressed either as a percentage of bill savings (i.e., self-reported percentages) or as "somewhat" or "very much" more or less than bill savings (i.e., labeled magnitude scaling).

The conjoint analysis survey method, commonly used in marketing research, essentially involves assessing the value of various hypothetical attributes of a product, through multiple questions asking respondents to choose between two hypothetical products, or scenarios with different combinations of the attributes in question. In some of these pairs, a monetary value replaces one of the attribute bundles. These preferences are then analyzed to obtain the monetary value of each of the attributes.[46]

Finally, depending on the perspective that the regulator wishes to consider, tax credits may be considered participant benefit associated with DER programs. Tax credits may include any federal, state, or local tax credits which may become available to participants for energy efficient measures, demand response equipment installation, or generation installations (CPUC 2010). As described below, from the societal perspective, this benefit can be considered a cost to taxpayers, and therefore becomes a transfer of wealth between two parties.

Accounting for Costs to Participants

Costs to participants fall in two categories, as illustrated in Table 10:

1. Participant direct costs
2. Other participant impacts

Quantification: **Direct costs to DER owners include** costs of equipment and installation (including labor to install or maintain equipment), as well as transaction costs (such as the time invested in evaluating options). These costs may be quantified by calculating the hours invested by the participants, interest rates on loans, payments to contractors, the cost of replacement components, and similar costs.

Other negative participant impacts may include increased heating or cooling costs, reduced comfort, and value of lost service from curtailment. Additional heating and cooling costs may be quantified by the additional energy (measured in therms or kilowatt-hours) consumed by the participant, after controlling for other variables (such as weather) through a regression analysis or similar method.

Reduced comfort is not directly quantifiable, but aspects such as indoor temperature increase or decrease can be quantified to aid in determining the magnitude of this impact. Load curtailed, measured

[46] Research has found that if participants are asked to estimate the value of individual impacts (i.e., thermal comfort, sense of environmental responsibility, etc.) and then asked to estimate the overall value of all of the individual impacts together, the sum of the individual values often substantially exceeds the overall estimated value of the combined impacts.

in kilowatt-hours to capture both the magnitude and duration, can be used to quantify the service lost during a demand response event.

Monetization: Most capital and O&M costs are directly monetizable through payments rendered for services or equipment, or financial calculations on loans. Transaction costs may be calculated in terms of "opportunity costs" through the use of an assumed wage rate, which varies by participant. Median or average wage rates for a specific geographic location could be used as a proxy for specific participant rates.

Additional heating or cooling costs can be directly monetized through use of market prices multiplied by the additional energy consumed.

The value of each unit of reduced comfort (e.g., per degree temperature rise) and load curtailed (per kilowatt-hour) can be measured through surveys. Market transactions for demand response enable a ceiling to be identified for these values, and, through multiple iterations, can help to identify the value that participants assign to comfort and electricity service. Participants will only accept payments that are equal to, or exceed, their costs of participation. Surveys or econometric models can also aid in determining the "supply curve" of participant costs (measured by participants' willingness to accept different payments for different levels of reduced comfort or load curtailment.)

Accounting for Benefits to Society

As shown in Table 11, benefits to society from DERs can be grouped into two categories:

1. Public benefits
2. Environmental benefits

Public Benefits

Quantification: Quantification of public benefits relies first on calculation of many of the direct benefits listed above, such as the reduced energy consumption of government buildings, or the reduced cost of energy faced by businesses. In addition, quantification of some costs (such as equipment installation costs or hours of consulting labor) is required to calculate economic impacts (explained below).

Monetization: Economic development impacts and tax impacts are frequently quantified using an input-output economic model or general equilibrium model. Such models quantify the changes to an economy due to direct impacts such as lower costs of energy, reduced taxes required to operate public buildings, increased demand for providers of DER-related services, or higher worker productivity due to improved health. Economic models then trace the effects of these impacts as they ripple through the economy. Impacts are frequently quantified in terms of jobs or economic output (in dollars).

Environmental Benefits

Quantification: Avoided emissions both reduce the costs of environmental compliance (e.g., purchasing emissions compliance permits, as discussed under the heading of "Benefits to All Utility Customers"), and reduce the real health and natural resource impacts (including climate change) generated by those emissions. This section refers to the latter – the reduced pollution or natural resource damages felt by society.

Emissions impacts are typically first quantified in terms such as tons of greenhouse gas pollution avoided, reductions in the concentration of pollutants in the air, or reduced quantities of toxins in freshwater streams.

Monetization: The value of reducing carbon emissions can be estimated using the federal government's Social Cost of Carbon (SCC). The SCC is an estimate of the economic damages from incremental increases in CO_2, including changes in net agricultural productivity, health damages, and property damage from increased flood risk. The damages do not currently include all of the likely damages of climate change due to a lack of precise data on the nature of the damages (EPA 2013b; Interagency Working Group 2013).

Tools such as the EPA's Environmental Benefits Mapping and Analysis Program (BenMAP) can be used to estimate the health impacts from reducing certain emissions (such as $PM_{2.5}$, NO_X, and SO_2) (EPA 2013a). Once the avoided emissions have been quantified, these are translated into avoided mortality and morbidity rates. BenMAP can then be used to monetize the expected health benefits to society.

Other natural resource impacts may be quantified using metrics such as improved crop yields or reductions in fish mortality rates. These impacts may be translated into higher farm incomes or greater recreational revenues through economic analyses. In addition, non-use value – the value not associated with actual or planned use of the resource – may be estimated through contingent valuation, relative valuation, or conjoint analysis, as discussed under Participant Benefits, above.[47]

Accounting for Costs to Society

As shown in Table 12, the possible costs to society from DERs can be classified as:

1. Public costs
2. Health and environmental costs

Quantification: Although tax credits merely represent a transfer from one member of society to another, [48] taxes impact the distribution of wealth. As such, they are relevant to the BCA framework to

[47] Examples include existence value (e.g., satisfaction of knowing that a species or ecosystem exists) and altruist value (satisfaction of knowing that others have access to an environmental benefit.)

[48] Taxes may also cause distortionary impacts on markets that result in what is called a "deadweight loss" to society, unless the tax is correcting for an externality, in which case it may improve market efficiency. These impacts are not addressed in this report, as the choice of the optimal tax (and any positive or negative impacts it may cause) is beyond the scope of this framework.

the extent that they result in a transfer of wealth from members of society that of concern to New York policymakers. The term “society” is critical here: if “society” is defined globally, no loss of wealth occurs. If “society” is defined as the citizens of New York, then taxes paid by New Yorkers that fund federal tax credits to residents of other states results in a loss of wealth to New Yorkers.

Environmental externalities in this category represent the environmental damages caused by increasing consumption of energy or changing the timing of energy consumption in a manner that increases emissions and other natural resource impacts. In addition, DERs may negatively impact land and water resources through the manufacturing process, installation location, and disposal. These may include the use of hazardous materials in photovoltaic manufacturing, habitat loss due to installation in sensitive areas, and contamination of soil and water through improper disposal. Although real, these impacts are likely to be small because distributed generation resources are typically installed on or close to buildings and other developed areas, and because manufacturers have a strong incentive to ensure that the valuable rare earth materials in DERs are recycled. Moreover, these impacts should only be accounted for if traditional technologies are given equal treatment.

Monetization: Monetization of the cost of tax credits is straightforward once the boundary of “society” is determined. Environmental externalities may be monetized through many of the methods discussed above, including use of EPA’s BenMAP tool and its estimated Social Cost of Carbon; conducting economic impact analyses to capture the costs of reduced farm yields or lower recreational tourism; and contingent valuation, relative valuation, or conjoint analysis to estimate the non-use values of habitat destruction, species loss, and related impacts.

August 21, 2015

VIA ELECTRONIC FILING

Hon. Kathleen H. Burgess
Secretary to the Commission
New York State Public Service Commission
Empire State Plaza, Agency Building 3
Albany, New York 12223-1350

Re: Case 14-M-0101 – Proceeding on Motion of the Commission in Regards to Reforming the Energy Vision

Dear Secretary Burgess:

The Advanced Energy Economy Institute (AEEI), on behalf of Advanced Energy Economy (AEE), the Alliance for Clean Energy New York (ACE NY), the New England Clean Energy Council, and their joint and respective member companies, submit for filing these Initial Comments to the *Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding,* in the above-referenced proceeding.

Respectfully Submitted,

Ryan Katofsky
Director, Industry Analysis