August 30, 2016

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 16-M-0412 – In the Matter of Benefit Cost Analysis Handbooks
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 *corrected* Initial Comments to the BCA Handbooks in the above-referenced proceeding.

The version we filed on August 29th omitted a graph (Figure 1). That has been corrected in the attached version. There are no other changes to the comments.

Respectfully Submitted,

Ryan Katofsky
Director, Industry Analysis

Response to "Notice of New Case Number and Soliciting Comments on the Benefit-Cost Analysis Handbooks" (Case 16-M-0412)

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

Preface

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 its continued commitment to the Reforming the Energy Vision (REV) proceeding, 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 Commission's July 27, 2016, notice seeking comments on the Benefit-Cost Analysis (BCA) Handbooks, 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.

In order to better respond to the Commission's request for comment on the BCA Handbooks, AEEI, along with other parties (Pace, SEIA, Vote Solar, and NRDC), pooled resources to hire Clean Power Research to review the BCA Handbooks. The parties then used Clean Power Research's review to each develop their own comments. As we have done throughout the REV proceeding, AEEI developed and is filing these comments with its partner organizations, ACE NY and NECEC.

Summary of Comments

The development of the BCA Handbooks is a complex undertaking, particularly since the approaches must apply to multiple technologies and rely on data that may not be readily available. In addition, the BCA Handbooks should be applicable to specific projects, portfolios of projects, and DER deployed via tariffs. Although the BCA Handbooks are generally responsive to the BCA Order, we conclude that the utilities were unable to meet the requirement of developing complete methodologies. Instead, possible approaches were developed and illustrative examples and results were offered that provide insight into possible methodologies that could be used, but commitments to definitive methods were not generally made.

We support the development and use of the BCA Handbooks as envisioned by the Commission, but the handbooks must comply with the requirements set forth by the Commission in order for them to have the intended effect. As such, we recommend that the Commission not accept the first version of the BCA Handbooks in their current form. Instead, we propose that the utilities consider the comments included in this document and other comments from other parties and provide updated and complete methodologies in revised BCA Handbooks. We anticipate that the new versions will include significant and new details that were not made available in the first versions, and they should therefore but subject to further public review by interested parties.

We also are concerned about the inclusion of participant costs of DER in the Societal Cost Test without equal consideration of the benefits that accrue to those same customers. While the approach that utilities took was consistent with the BCA Framework Order, we emphasize that it will lead to lopsided results that do not fully account for costs and benefits to society. We also note that the Commission's Framework Order states that Non Energy Benefits (NEBs) can be included if there are means for accurately valuing them. We ask that the Commission consider some of the methodologies for quantifying NEBs that are widely accepted in neighboring jurisdictions.[1]

We also recommend that the utilities consider the details that we provided in our April 18, 2016, filing in Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources.* As part of that

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

filing, we provided a technical appendix that outlined methods for calculating the components of LMP+D, based on the BCA Order.

Background and Purpose

The BCA Framework Order[2] of the New York Public Service Commission directed state investor-owned utilities to develop methodologies that would be used in performing benefit-cost analyses (BCAs) for distributed energy resources (DERs) under the state REV initiative. The Order further described the framework and guiding principles to be adopted, and it called for the utilities to develop and file Distributed System Implementation Plans (DSIPs) and accompanying BCA Handbooks for this purpose.

On July 27, 2016, the Commission issued a notice[3] seeking from interested entities comments related to the BCA Handbooks as filed by the utilities. The comments that follow are in response to this notice.[4]

The BCA Framework Order requires that benefit-cost analyses be applied to the following four categories of utility expenditure:

- Investments in distributed system platform (DSP) capabilities
- Procurement of distributed energy resources (DER) through competitive selection
- Procurement of DER through tariffs
- Energy efficiency programs

These four applications may require certain adaptations, depending on usage. For example, the procurement of DER through competitive solicitation might be justified based on a BCA, but compensation to the equipment supplier would be based on competitive bids. The development of tariffs, on the other hand, would define compensation rates, and these tariffs may be designed for per-kW and/or per-kWh compensation using an extension of the methods set forth in the BCA Handbooks. In all cases, however, the underlying technical methods, such as the treatment of losses or the development of technology production profiles, would be defined in the BCA Handbooks.

[2] "Order Establishing the Benefit Cost Analysis Framework," Case 14-M-0101, January 21, 2016.
[3] "Notice of New Case Number and Soliciting Comments on the Benefit-Cost Analysis Handbooks," Case 16-M-0412 and Case 14-M-0101, July 27, 2017.
[4] These comments are prepared with the assistance of Clean Power Research, Napa, California.

Use of Central Hudson BCA Handbook

The BCA Handbooks were developed jointly by the utilities, simplifying the review process. They generally have the same content, although appendices are made available for utility-specific results.

To simplify the comments provided here, page numbers reference the specific BCA Handbook filed by Central Hudson Gas and Electric,[5] herein called "the Handbook." The selection of this particular BCA Handbook was largely arbitrary and primarily for convenience based on file formatting considerations. References to BCA Handbooks filed by other utilities are included, as necessary, when differences among the individual BCA Handbooks are relevant. The Handbook draws results in several places from an independent study[6] performed by E3, so these comments also reference this study in several places.

Readiness of BCA Handbooks

The BCA Framework Order states:[7]

> Effectively assessing the benefits of DER requires accurately assessing the amount of energy, capacity, and other benefits that those resources provide, and how often, when, and where they will be provided. Therefore, the BCA Handbooks shall detail a methodology that: 1) characterizes DER resource profiles, and 2) determines to what degree those resources reduce energy or capacity and ancillary service needs.

The development of such a methodology is obviously a complex undertaking, particularly since it must apply to multiple technologies (e.g., the methodologies must apply to both intermittent and non-intermittent resources) and rely on data that may not be readily available (e.g., utility studies that differentially quantify fixed versus variable losses).

Given the technical challenges, the utilities were unable to meet the requirement of developing complete methodologies. Instead, possible approaches were developed and illustrative examples and results were offered that provide insight into possible methodologies that could be used, but commitments to definitive methods were not generally made.

To take one example, there is no method specified for calculating a "system coincidence factor" for distributed solar. This factor is a critically important numeric parameter used in the valuation of this resource type. Yet, the Handbook does not offer a methodology. It states (p. 59) that there are "multiple approaches" that could be used, and it indicates that "an area for further investigation will be to assess and develop a common approach and methodology (p. 60)."

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[5] "Central Hudson Gas and Electric Benefit-Cost Analysis (BCA) Handbook" Version 1, June 30, 2016.

[6] The Benefits and Costs of Net Energy Metering in New York, Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service, December 11, 2015.

[7] BCA Framework Order, pp. 31-32.

The Handbook does include sample coincidence factors taken from the E3 study, but it also refers to "actual locational estimates" (p. 61) in an appendix that relies on a method different than the E3 study. The E3 method is based on a fleet of 30,000 systems across the state, while the other method is based on a single, energy optimized system (south-facing, 35-degree tilt). It is not clear which of the two alternatives may be incorporated into a future BCA Handbook methodology. It is also not clear whether, in the course of further investigation, the utilities will develop a new methodology not presented in the Handbook.

In addition, the Handbook did not consider the full range of DER technologies. Energy storage, electric vehicle charging strategies, fuel cells and demand side technologies, like building pre-cooling, need to be included in order to be compliant with the BCA Framework Order.

The comments here are offered with the intent of helping to guide the process of developing a definitive BCA Handbook that meets the requirements set forth by the Commission. It follows that updated BCA Handbooks, once the methodologies are defined, should still be open to public review at that time.

Relevant Cost-Effectiveness Tests

Utilities should provide more context to RIM scores

The BCA Framework Order appropriately adopts the Societal Cost Test (SCT) as the primary measure of cost-effectiveness under the BCA framework. Nevertheless, the Rate Impact Measure (RIM) test continues to serve a subsidiary role.[8]

With regard to the utilities application of RIM test in the Handbook, we offer the following recommendations:

Recognizing that RIM ratios show only if a rate increase or decrease will be realized and do not provide information surrounding the actual magnitude of a program's impact on customer bills, the BCA Framework Order wisely prohibits rejection of an SCT-passing DER proposal owing to a failing RIM ratio absent detailed bill impact analysis.[9] But the Order requires utilities to report rate impact estimates only for rejections. This is problematic because, although RIM ratios are meaningless in some ways and perverse in others (see Appendix 1), poor RIM ratios for programs and projects being approved, without further context, could reduce their scale and scope, prejudice the prospects for the future development of similar SCT-cost-effective DER efforts, or cause a reduction in the scale and scope of programs that are approved.

To prevent poor RIM scores from inappropriately influencing regulators and utilities as they develop and approve current and future programs, we recommend that utilities be required to carry out

[8] BCA Framework Order, p. 12.
[9] BCA Framework Order, p. 13.

simple analyses to accompany all RIM ratios less than 0.9, thereby providing some context regarding how the program might be expected to affect customer bills. This could be done using a simplified, easy template calculation reflecting the utility's revenue requirement.

While more detail and accuracy could be agreed upon, the simplest template algorithm would be:

- Assume all the measures to be installed by a program will be installed (and utility costs incurred) in the first year;
- Calculate all the variables below as measure-life, present-valued;
- From the B/C software RIM formula calculations or columns of annual values, take the outputs for lost revenues, DER-caused-energy-purchase utility $ savings, and utility program costs;
- Calculate the total revenue requirement on all sales based on simple assumptions of flat annual sales and costs (i.e., simply extend the annual current revenue requirement unless inflation is modeled);
- Divide the utility's net cash flow loss (lost revenues plus program costs minus supply savings) by the approximate revenue requirement for the net cash flow losses as a percentage of the revenue requirement; and
- Disregard all issues of customer class, timing of recovery, and rate design.

Even this basic calculation would be far more useful than a RIM ratio itself for purposes of understanding how a given program might shift recovery of the utility's revenue requirement between its customers. Agreed refinements could include:

- Adjust the revenue requirement for predicted real changes in marginal supply costs, such as those owing to predicted fuel price changes;
- Increasing the percentage rate impact by analysis at the kWh level – capturing that the revenue requirement must be spread among fewer sold units owing to DER reductions in sales; and
- Adjusting the revenue requirement for predicted load growth, at a flat annual rate.

Utility Cost Test (UCT)

It would be instructive for the utilities to prepare levelized cost of saved energy values for the different types of DERs, and even the different DERs. While this only includes the utility costs and does not represent all of the benefits, it would be helpful nonetheless in providing a sense of priorities across DERs.

Technical Methods

Establishing Credible Baselines

The Handbook mentions the challenges of identifying the baselines, but does not address one of the critical elements of the baseline: which DERs are assumed to be installed in the baseline? We recommend that the base of DERs installed prior to the DERs under evaluation be included in the baseline. The LMP+D tariff would be computed assuming a load shape that incorporates the existing fleet of DERs that are subject to NEM.

Establishing Appropriate Time Horizon for Analysis

The Handbook reinforces (p. 15) the BCA Framework Order's foundational principle that the analysis should "address the full lifetime of the investment."[10] This is also consistent with principles of engineering economic analysis.

However, the Handbook does not address the full lifetime of the investment, but rather only a single year of the investment. The several equations proposed for calculating benefits are based on a framework that considers only a single year (year Y). The Handbook approach thereby significantly undervalues the stream of benefits from long-lived measures, such as distributed generation, equipment upgrades, and building efficiency improvements.

A properly designed framework would calculate benefits from each year of the analysis period and sum the discounted results. An example framework that could be adopted for this purpose is included in the methodology[11] approved by the Minnesota Public Utilities Commission in 2014 for valuation of distributed solar resources.

Incorporating Losses into Benefits

The Handbook (p. 13) agrees with the BCA Framework Order in that losses are differentiated between fixed (not avoidable) and variable (potentially avoidable). However, the calculation of loss factors does not reflect load dependency as required by physical laws. It also does not agree with the BCA Framework Order, which characterizes these losses as proportional to the square of the current (I^2R losses).

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[10] BCA Framework Order, p. 2.

[11] Norris, et. al., "Minnesota Value of Solar: Methodology," April 2014, available at: http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf

Variable losses are strongly dependent upon the loads in each hour. When load is low, variable losses are low, and when load is high, variable losses are high.

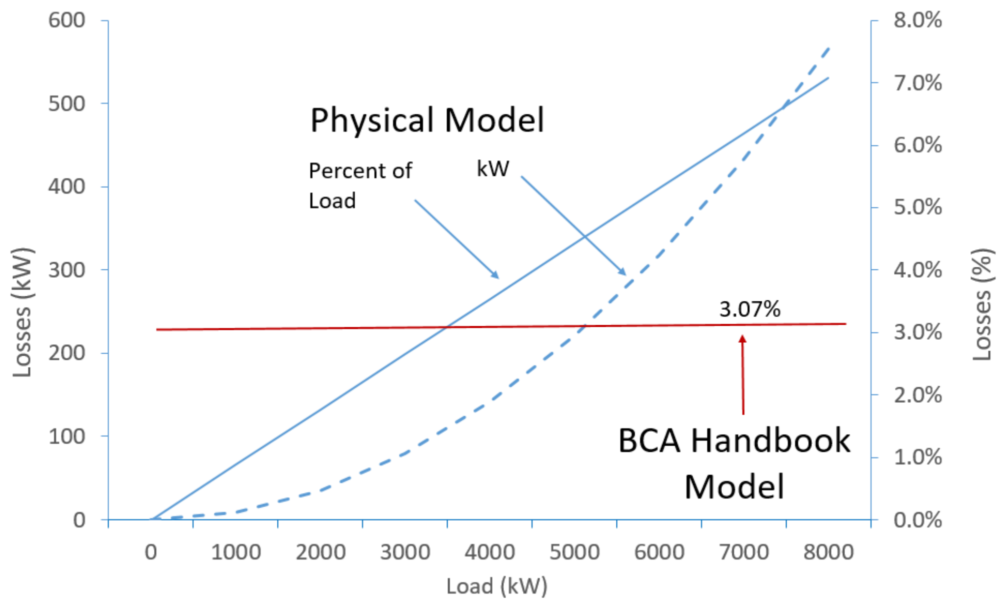

Figure 1 shows a sample calculation of losses as a function of load. The example calculates physical losses (blue) derived from the BCA Framework Order, namely, the annual average variable loss factor example of 3.07%. Hourly losses range from 0% at no load to 7% at full load. The proposed BCA Handbook method is also shown (red) in which losses are independent of load, i.e., they are constant at 3.07% regardless of load.[12]

The proposed methodology will generally result in understatement of avoided losses for DERs. This is because most DERs will be operated to produce power during times when load is higher than average.

For example, a storage system would likely be dispatched to deliver energy during the hours of greatest need, e.g., during the highest 20% of loading, when the losses are between about 6% and 7%. Similarly, solar resources, while not dispatchable, also produce power than can be correlated with load (i.e., during hours when load is higher than average), so loss factors for solar will also exceed the assume 3.07% annual average.

To rectify this problem, the methodology proposed in the AEEI-ACENY-NECEC original filing in the LMP+D proceeding is recommended.[13] This is included in Appendix 2. If the Handbook methodology were modified to incorporate such an hourly loss savings calculation and to summarize these into annual loss savings factors (e.g., by technology and benefit category), that would also be acceptable.

[12] The Central Hudson loss factor of 6.73% was not used here because it includes both fixed and variable losses.

[13] Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources, filing dated April 18, 2016.

Other Comments:

- The methodology should be simplified to treat avoided losses consistently. For example, avoided losses appear to be included in the avoided LBMP benefit calculation (Equation 4-2) but also in the avoided distribution loss benefit (Equation 4-10), thereby double-counting the benefit. On the other hand, the avoided transmission capacity infrastructure benefit (Equation 4-3) includes the effects of avoided losses, but the benefit is excluded from the avoided distribution loss benefit (Equation 4-10). To simplify, either (1) all of the individual benefit component calculations should incorporate the effects of losses (while removing the avoided transmission loss and avoided distribution loss components), or (2) all of the avoided loss benefits should be included in, and only in, the respective loss categories.
- The Handbook excludes avoided losses in the case of frequency regulation, spinning reserve, avoided SO_2, and avoided NO_x. Avoided losses should be included in these cases for the same reason as they are included in other capacity and energy-related benefits.
- Central Hudson loss data indicates that studies are not available to differentiate between fixed and variable losses. Such a study should be conducted to complete this task. Until such time as the results from the study are available, an estimate should be made. Using ConEdison's data from the BCA Framework Order (p. 12), for example, fixed losses total 1.67% and variable losses total 4.79%. The variable losses are therefore 4.79/(1.67 + 4.79) = 74% of the total. Applying this to the Central Hudson total losses of 6.73%, a temporary estimate of variable losses might be 6.73% x 74% = 4.98%.
- Orange and Rockland (Table A-2) does not total or accumulate losses for lower voltage levels. For example, energy delivered to a customer on primary distribution would incur transmission losses of 1.3% plus primary distribution losses of 1.08%, for a total of 2.38%, however this is not indicated. The Handbook should clarify this.
- The method does not appear to acknowledge that the avoided distribution losses should be taken into account when calculating avoided transmission losses. This should be corrected.

Characterization of DER Profiles

It is not clear how Table 5-3 would be used in a future BCA evaluation. For example, energy efficiency is shown as only partially (half-circle) avoiding the cost of future transmission capacity. How this characterization would be used in the analysis is not explained. Nonetheless, it is useful to provide some feedback on the table:

- All of the technologies shown reduce transmission losses, yet the table indicates no benefit. If DER were not delivering energy, the energy instead would be provided by resources connected to the transmission grid and would thus incur transmission losses. For example, the Net Avoided CO_2 benefit is augmented by the fact that centrally-located carbon producing resources, connected to the transmission system, do not have to over-produce in order to compensate for transmission losses.
- Similarly, the table suggests that DER does not avoid any distribution losses. This is not correct because energy provided by DER reduces the amount of energy that must pass through the distribution system.

Coincidence Factors and Derating Factors

The Handbook includes two factors that require further clarification: the coincidence factors and the derating factors. These factors occur in multiple benefit calculations and are tailored to each, e.g., the Transmission Coincidence Factor applies to the transmission capacity benefit while the System Coincidence Factor applies to the avoided generation capacity benefit. The comments that follow are general and apply to all of these benefit calculations.

Such factors, insofar as they properly account for availability, dispatchability, differences in rating conventions among DER technologies, or other effects necessary to the evaluation of benefits in the BCA calculations, should be included in the BCA Handbooks. However, the Handbook does not adequately define these two factors or illustrate their calculation methods, and in some cases indicate double-counting of performance-related impacts.

Derating Factors

The derating factor used in the avoided generation capacity costs (p. 22), for example, is purportedly used to address the "variability and intermittence (e.g., due to clouds) of a solar array." However, the variability is also included in the calculation of coincidence factors (p. 59-60). The example approach provided in calculating coincidence factors for solar is based on modeled hourly solar production. Therefore, since cloud impacts and intermittence are included in both the derating factor and the coincidence factors, this is double-counting the impacts of clouds and intermittence, counter to the principles established in the BCA Framework Order.

Other definitions could be developed for the derating factors that would be meaningful and in keeping with the principles of the Framework Order. For example, solar derating factors could be developed to account for system losses not captured in DC module nameplate ratings at standard test conditions. Such losses could include such effects as module temperature effects, module mismatch losses, and inverter losses. However, such a definition of the derating factor was not pursued in the Handbook, which defined the factor in terms of "availability of the resource during system peak hours."

Due to the double-counting and lack of clarity regarding these derating factors, they should either be removed or the Handbook should be re-written to clarify the meaning and methods related to the calculation of the derating factors.

Coincidence Factors

As described above, the Handbook does not indicate which of several possible methods would be used in calculating coincidence factors. This complicates this review because, with multiple options available, it is not clear which, if any, would be used by the utilities in conducting the BCA evaluations. It is not clear how the published "illustrative" results tables would be used or what they illustrate. Are the published numeric results going to be used in the BCA studies? Are they suggesting what results would be expected once a methodology is decided? Are they used to imply which of the methods will be selected? The BCA Handbooks should be re-written to clarify these points and define a methodology.

The comments that follow are therefore intended to address selected points in the example coincidence factor approaches included in the Handbook.

- The Handbook only addresses PV, CHP, DR, and EE. Other technologies, such as storage, fuel cells, and load shifting should also be included.
- The example solar coincidence factor calculation is based on a single energy-optimized 4 kW-AC unit (p. 61), yet the illustrative coincidence factors are based on 30,000 systems from NYSERDA's PV Sun database. So, it is not clear which resource(s) would be used to develop solar production profiles.

  The BCA Framework Order states that "the BCA analysis should… assess portfolios rather than individual measures or investments (p. 2)," suggesting that the fleet-wide analysis would be better suited than an analysis of a single system. This is our recommendation. Such an approach would result in a solar production profile that aggregates the range of design orientations (tilt and azimuth angles). The E3 approach of using the PV Sun database would meet this objective, but it should be corrected using solar data measured at the same time as load as noted below.

- Figure 5-1 (p. 60) illustrates the concept of applying DER load profiles to peak hours. However, the figure appears to suggest that a single peak hour would be used to calculate the numeric result. While the NYCA Peak is shown as a single hour (hour ending 17) as a determinant of the coincidence factor calculation, the underlying E3 report indicates that DER output over the 100 peak load hours was used. This discrepancy makes the methodology unclear. The use of the 100 peak load hours would be a sound approach, but this should be stated if it is being proposed.
- There are discrepancies in results. For example, the DR system coincidence factor in Figure 5-1 is 0%, but the DR system coincidence factor in Table 5-9 (p. 65) is 100%. Other discrepancies occur across technologies.
- Table 5-7 shows a solar "system coincidence factor" of 36% but a "distribution coincidence factor" of only 7%, a noteworthy difference in result. Yet, the distribution coincidence factor is referred to as a "statewide weighted average." In any given hour, the sum of the statewide distribution loads is about the same as the statewide system load (neglecting imports/exports), so the statewide coincidence factor should be similar. There are certainly some feeders (e.g., those with heavy residential load components) where the distribution peaks differ significantly from the system peaks, but the discrepancy in statewide results indicate a possible error in the calculation. The underlying data for this analysis should be made available for review.

  Furthermore, the methodology does not make clear whether it recommends use of the statewide weighted average or other metric, such as a coincidence factor corresponding to a particular utility or feeder associated with a resource.
- The coincidence factors are expressed as a percentage of nameplate capacity. However, the nameplate rating convention used is not specified. For solar PV, the convention could be, for example, standard test conditions DC module rating, PVUSA test conditions with inverter losses included (AC), or some other industry convention.
- The solar data used to derive the coincidence factors was not measured at the same time as the electrical load, so the coincidence was lost, making the coincidence factors inaccurate. This is because "typical" year data was used for the solar profile, rather than "actual" data. As an illustration of the error introduced by using data measured at two different times, Figure 1 shows the NYISO load on July 29, 2015, the peak day of that year. Two solar production profiles for PV located in Albany (south facing, 35-degree tilt) are shown, one using actual solar data[14] measured on that day, and the other using the "typical" year data employed in the Handbook analysis.

  According to the data used in the Handbook methodology, the year 1977 would have been selected as the typical year for Albany in July, so in this illustration solar modeling was

[14] Modeled solar output using Clean Power Research SolarAnywhere satellite-derived data.

performed for July 29, 1977 and compared to NYISO load data from July 29, 2015. Unfortunately, the 1977 day included patchy clouds and poor afternoon resource, while the actual peak day in 2015 was clear. Thus the correlation between solar production and NYISO peak load was ignored in the Handbook methodology.

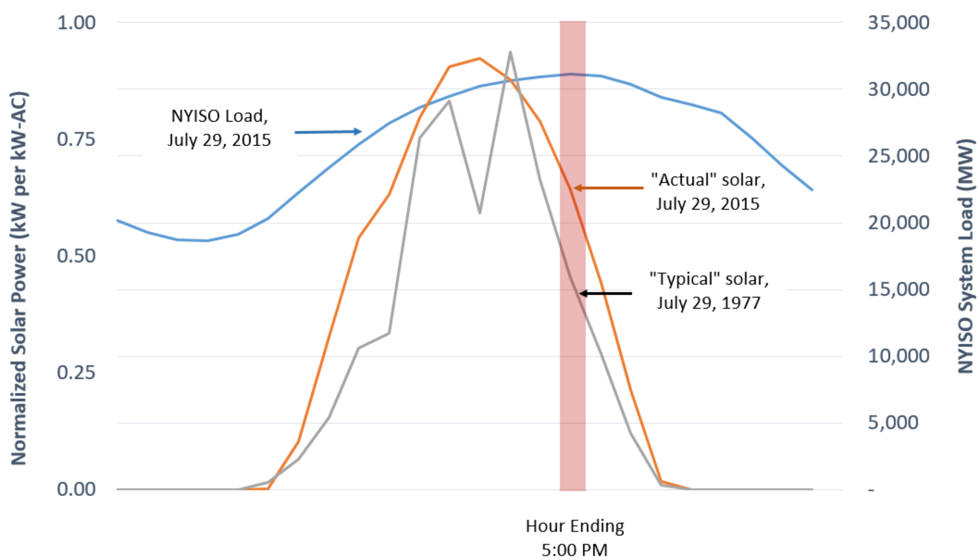

Figure 1. July 29 load and solar modeling for Albany.

Actual solar output at the peak hour was 0.642 kWh per kW-AC, 42% higher than the 0.453 kWh from the Handbook technique. This error should be eliminated by correcting the technique to use solar data collected at the same time as the load data, whether for the system, transmission, or distribution coincidence factors.

- The use of typical year data further implies that a single study year is used as the basis of the coincidence factor calculations.[15] The methodology should be modified so that its coincidence factors are not dependent upon a single solar year, that may not be generally representative. Either of two approaches may be taken:
  - Option 1 is to lengthen the technical study period to several years (e.g., five years). Actual solar data from these five years—not typical data repeated each year—would be compared against actual load data from these five years.

[15] Strictly speaking a typical meteorological year (TMY) data set for a given location comprises 12 typical months: a typical January, a typical February, etc. Thus the TMY year contains data selected from up to 12 years. By compiling these 12 months into a single year data set, the typical year becomes, in effect, a single study year of data.

- Option 2 is to develop a weather normalized year. This approach would be conceptually similar to the development of typical year data, but would retain the coincidence between solar and load. The method would be to develop a time-aligned data set in which an underlying common meteorological data set (irradiance, temperature, etc.) is used to calculate both solar production and load (e.g., load is calculated using empirical relationships from current temperature, three-day moving average temperature, etc.).

- The description of the CHP example system coincidence factor (95%) indicates that it reflects resource availability (based an assumed outage rate of 5%). Yet the description of the derating factors (p. 22, 26, 34) indicates that this factor is also designed to reflect the availability of the resource. This appears to be double-counting.[16]

Benefits and Costs Methodology

Avoided Generation Capacity Costs

- The methodology is agreeable, except that it should be modified as described above to correctly account for the time horizon, the hourly losses, the coincidence factor, and the derating factor.

Avoided LBMPs

- The methodology is agreeable, except that it should be modified as described above to correctly account for the time horizon, and the hourly losses.
- It is not clear why any interval other than hourly would be used for the analysis.

Avoided Transmission Capacity Infrastructure

- The methodology is agreeable, except that it should be modified as described above to correctly account for the time horizon, the hourly losses, coincidence factor, and the derating factor.

Avoided Transmission Losses

- The methodology is incomplete as it addresses only energy and generation capacity. It should be modified to apply to other upstream benefits, such as avoided carbon and avoided transmission capacity infrastructure.

[16] Possible sources for this coincidence factor could be the NYSERDA CHP database (http://chp.nyserda.ny.gov/home/index.cfm) and a Rutgers University study specific to CHP in New York (http://ceeep.rutgers.edu/wp-content/uploads/2016/02/WP2-Do-CHPs-Perform-Case-Study-of-NYSERDA-funded-Projects-11302015.pdf)

- Loss calculations should be corrected as described above (e.g., calculate on hourly basis using load-dependent model, include distribution loss impacts, etc.).
- The use of the year Y+1 notation is unclear. The losses apply to all years (Y, Y+1, Y+2, etc.).

Avoided Ancillary Services

- The methodology for wholesale ancillary services is agreeable.
- Two additional benefits that some DER technologies, like fuel cells and energy storage, provide to the grid are not considered in the Handbook. Power factor improvements and voltage management both contribute to more efficient grid operation and should be considered in a holistic value of DER assessment.

Wholesale Market Price Impact

- The methodology is agreeable[17], except that:

    - It should be modified as described previously to correctly account for the time horizon and the hourly losses.
    - The impact should be evaluated during hours of DER operation, not based on annual averages. The hours should correspond with hourly avoided LBMPs.
    - The benefits should not apply for only one year, but rather this should be evaluated based on the time to install new capacity (engineering, approvals, financing, etc.).

Avoided Distribution Capacity Infrastructure

- The Distribution Coincidence Factor is defined as "the contribution to the distribution element's peak relative to the project's nameplate demand reduction." For example, a 100 kW resource with a factor of 0.8 would reduce the peak load by 80 kW. However, the example solar PV benefit example (Table 5-7, p. 61, shown as 7%) contradicts this definition.

    The distribution coincidence factors were taken from the E3 study, which incorporated the probability of load exceeding a substation rating. A substation with excess capacity would have a low probability of load exceeding rating, so DERs connected to this substation would have

[17] We understand that there is opposition to including wholesale market price impacts as compensation to DER, but when these impacts are considerable and result in significant savings, the Commission could consider paying some of it in the form of compensation to DER and reserving the rest as savings for non-participant customers. This impact should be considered a utility avoided costs and should be recognized for tariff-based compensation (not only in the SCT evaluation). This is because DER displaces payments that the utility would otherwise make to procure wholesale power in the marketplace. Since DER lowers the cost of wholesale power, this is a savings that would be compensated.

a low coincidence factor, even with a high coincidence between DER output and load. The method used, in effect, is a reflection of the surplus, unused distribution capacity installed by the utilities. The methodology should be changed to reflect only the coincidence of DER production and distribution load as stated in the definition of the coincidence factor.

- The marginal distribution costs (Table A-3, p. B-1) also reflect the surplus of capacity in the distribution system. Note, for example, that marginal costs are zero for the first four years beginning in 2016. Since surplus capacity is indicated in both the distribution coincidence factor and the marginal costs, the methodology double-counts this effect, contrary to the BCA Framework Order principle.
- The methodology appears to recognize a maximum of ten years of asset life because only ten years of marginal costs are provided. A method should be developed to incorporate the benefit for all years (e.g., a storage system with a life of 20 years should account for 20 years of benefits). One way to accomplish this is to extrapolate the marginal costs using a spline fit or similar method.

Avoided O&M

- The methodology is agreeable.

Avoided Distribution Losses

- The loss calculations should be corrected as described above.
- The description of loss benefits (p. 36) states that the benefit of avoided distribution losses would only be quantified "in cases where [the DER] alters the distribution system losses percentage." The meaning of this is unclear, because all generation originating and used in the distribution system will displace generation originating in the bulk system and delivered via the distribution system. Therefore, all DER generation alters the distribution system losses percentage.
- Equation 4-10 is incomplete. It recognizes only energy and generation capacity. It should also incorporate all other benefits (e.g., carbon benefit, distribution capacity benefit, etc.).

Net Avoided Restoration costs

- The methodology is agreeable.

Net Avoided Outage Costs

- The methodology is agreeable.

Net Avoided CO_2, NO_x, and SO_x

- The methodology is agreeable, except that it should be modified as described above to correctly account for the time horizon and the hourly losses.

Net Non-Energy Benefits

We note that the Commission's Framework Order states that Non Energy Benefits (NEBs) can be included if there are means for accurately valuing them. We ask that the Commission consider some of the methodologies for quantifying NEBs that are widely accepted in neighboring jurisdictions.[18]

Process for Finalizing BCA Handbooks

Given the above analysis of the BCA Handbooks, we recommend that the Commission not accept the first version of the BCA Handbooks in their current form. The current BCA Handbooks contain errors and ambiguities in their framework, input data, and methodologies. In many cases, the proposed methodologies are not defined.

We support the development and use of the BCA Handbooks as envisioned by the Commission, but the handbooks must comply with the requirements set forth by the Commission.

Therefore, we propose that the utilities consider the comments included in this document and other comments from other parties and develop new BCA Handbooks. We anticipate that the new versions will include significant and new details that were not made available in the first versions, and they should therefore but subject to further public review by interested parties.

Furthermore, to the extent that proposed numerical intermediate results are published in the new versions for use in the BCA analyses (e.g., tables of coincident factors or marginal distribution costs), the underlying data should be made available for review and independent confirmation of the calculations. In cases where a methodology is specified but numerical results are left to the future, we ask the Commission to allow public review of the results at the appropriate time in the future.

Appendix 1: RIM Test Issues

The RIM test compares the utility's cash flow losses (lost revenues plus program costs including incentives) to the utility's cash benefit of the savings on the purchase of power (chiefly kWh and MW)

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

monetized per forecasts of marginal costs (such as in NYISO markets). Revenues lost to DER are ratepayer bill savings at retail rates (with energy, demand, and customer charges aggregated).

For example, assume per kWh a retail rate of 19 cents and an average marginal supply cost of 10 cents (a utility's aggregate revenues and supply costs, respectively, both divided by kWh sales). In this case, the fixed costs (such as return, debt service, distribution maintenance, metering, and billing) would be nine cents. Assuming a utility implemented an energy efficiency program with a cost, including incentives, of 1 cent/kWh saved, the utility's cash flow loss would be 20 cents, the benefit 10 cents, and the RIM B/C ratio 0.5 (and net utility cash flow loss 10 cents). Yet the program would be SCT cost-effective provided that the participant's capital cost, net of rebates, is not more than the CO_2 value above nine cents.

The usefulness of the RIM test is limited and can lead to incorrect conclusions:

- No utility total revenue requirement estimate for the original (or remaining) sales appears in the RIM calculation, so there is no basis for a relationship to the magnitude of the rate impact (what is the net cash flow loss of [10 cents x kWh not sold] a percentage of?).
- The RIM ratio in large part reflects the proportion of a utility's fixed versus marginal costs, as opposed to characteristics of the energy efficiency or renewable technologies, programs, or projects.
- Retail rates always exceed a utility's marginal supply costs in order to recover its fixed costs. Therefore, almost no energy efficiency program can pass the RIM test, while other technologies, such as demand response, would be able to pass. While off-peak kWh conserved are desirable from an environmental perspective, the RIM perversely tends to punish measures which save electricity that has a lower average avoided marginal supply cost and therefore causes higher net lost revenues. If a demand response program somehow added off-peak kWh to its savings at no cost, its RIM ratio could go down (depending on Time of Use rates).
- Illustrating how providing context regarding rate impacts is more useful than RIM ratios alone, the 2015 E3 net metering report estimated modest rate impacts "on the order of ~0.1% to ~0.5%" across four solar PV scenarios versus ugly RIM ratios such as 0.76 for the middle, targeted scenario (although it passed the SCT at 1.06). *See* New York State Energy Research and Development Authority and New York State Department of Public Service, *The Benefits and Costs of Net Energy Metering in New York,* prepared by Energy Environmental Economics (December 11, 2015), at 5, 23, 53, figure 38.

Appendix 2: Loss Calculations

The following text was included in the original AEEI-ACENY-NECEC filing of the LMP+D proceeding. It is included here for convenience.

The BCA Framework Order indicates that technical losses include both fixed and variable losses. DER will generally only be able to avoid variable losses, and the BCA Framework Order also describes that these are proportional to the square of the current (I^2R losses). Theoretically, the calculation of avoided losses therefore requires the measurement of resistivity of each conductor on the system, and this would result in different loss factors for every DER location. Other complications also come into play, such as the fact that resistivity is a function of conductor temperature, so hourly ambient convective losses and solar heat gains that also contribute to conductor temperature also have indirect effects on loss factors.

Such a detailed calculation is not practical or desirable, so a simplification is proposed in which all losses in any given hour at all locations are only a function of load in that hour.

With this simplification, we may express the losses in hour t as αL_t^2 where L_t is the load and α is the constant of proportionality. Then, we can take advantage of loss study data, such as the data presented in the BCA Framework, Table 3 in Appendix C, that show annual line losses as a percentage of energy delivered. The example, given for energy efficiency, combined transmission and distribution loss percentages into a total percentage of 4.14%. This percentage may be generalized into the parameter p and, by definition,

$$p = \frac{\sum \alpha {L_t}^2}{\sum L_t}$$

Where the summations are for every hour of the year. From this we solve for α to get:

$$\alpha = p \frac{\sum L_t}{\sum {L_t}^2}$$

This equation allows us to determine α based on the loss percentage p taken from the loss study, and the hourly loads over a given year. This allows us to dynamically (i.e., hourly) calculate a “gross up factor" (the "loss savings factor") as suggested in the BCA Framework as follows. If the energy delivered as an output of the T&D system in hour t is $E_{delivered}$, then the input energy is given by:

$$E_{input} = \frac{E_{delivered}}{(1 - \alpha L_t^2)}$$

The loss savings factor for hour *t* is therefore:

$$LSF_t = \frac{1}{(1 - \alpha L_t^2)}$$

Loss savings factors (LSFs) would be calculated for each hour and applied to the prices for each component. Separate loss factors would be calculated for only those components that provide loss savings to the distribution system (e.g., Avoided Distribution Capacity Infrastructure) and those that provide both loss savings to both the distribution system and the transmission system. The procedure would be the same, but the percentage loss *p* would be different.

Loss savings apply to all of the other benefits and costs which have an associated hourly price. The methodology could therefore include one of two procedures: (1) calculate loss savings factors individually for each benefit, and multiply each component price by its associated LSF to obtain the adjusted component price; or (2) create a separate additive price to represent Avoided Distribution Losses (ADL) as follows:

$$Price_{ADL} = (LSF_1 - 1) \times Price_1 + (LSF_2 - 1) \times Price_2 + (LSF_3 - 1) \times Price_3 + \cdots$$