Benefit Cost Analysis (BCA) Handbook

Version 1.1

August 22, 2016

BCA Handbook Version

This initial BCA Handbook was developed and filed contemporaneously with the Distributed System Implementation Plan ("DSIP").

The Companies BCA Handbook will be updated each time the DSIP is updated; currently expected to take place every two years[1]. New York statewide and Companies specific data elements will be reviewed and updated as applicable.

This Version 1.0 of the Companies BCA Handbook is effective for two calendar years; through June 30, 2018 or until Commission directive requires other.

On an interim basis the Companies may update, as appropriate and applicable, specific data inputs; including requirements per the DSIP schedule and/or new guidance or Orders.

Version	File Name	Last Updated	Document Owner	Updates since Previous Version
V1.0	NYSEG-RGE BCAH V1.0 06-30-2016	06/30/2016	NYSEG-RGE	n/a
V1.1	NYSEG-RGE BCAH V1.0 08-22-2016	08/22/2016	NYSEG-RGE	Correction to equation 7-3 Avoided Transmission Capacity Infrastructure and Related O&M. Correction to equation 7-7 Wholesale Market Price Impact.

[1] DSIP Guidance Order, p. 64: "shall file subsequent Distributed System Implementation Plans on a biennial basis beginning June 30, 2018."

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1. Acronyms and Abbreviations

Acronyms and abbreviations are used extensively throughout the BCA Handbook and are presented here at the front of the Handbook for ease of reference.

ADMS	Advanced Distribution Management System
AGCC	Avoided Generation Capacity Costs
AMI	Advanced Metering Infrastructure
AVANGRID	An energy and utility subsidiary of IBERDROLA, S.A. that operates in the United States.
BCA	Benefit-Cost Analysis
BCA Framework	The benefit-cost structure as presented in the BCA Order
BCA Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016).
CAIDI	Customer Average Interruption Duration Index
CARIS	Congestion Assessment and Resource Integration Study
CO_2	Carbon dioxide
Commission	New York State Department of Public Service Commission
Companies	AVANGRID's two New York utility subsidiaries: NYSEG and RG&E
DER	Distributed Energy Resource(s)
DG	Distributed Generation
DR	Demand Response
DSIP	Distributed System Implementation Plan
DSIP Guidance	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Distributed System

Order	Implementation Plan Guidance (issued April 20, 2016)
DSP	Distributed System Platform
ES	Energy Storage
G&A	General and Administrative
GHG	Greenhouse Gas
Gold Book	2015 Load and Capacity Data Report
ICAP	Installed Capacity
JU	Joint Utilities (Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation)
kV	Kilovolt
kVAR	Kilovolt Ampere Reactive
LBMP	Locational Based Marginal Prices
LCR	Locational Capacity Requirements
LHV	Lower Hudson Valley
LI	Long Island
MW	Megawatt
MWh	Megawatt Hour
NEM	Net Energy Metering
NO_x	Nitrogen oxides
NWA	Non-Wires Alternative(s)
NYC	New York City
NYISO	New York Independent System Operator

NYSEG	New York State Electric and Gas
NYPSC	New York Public Service Commission
NYS	New York State
O&M	Operations and Maintenance
REV	Reforming the Energy Vision
REV Proceeding	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision
RG&E	Rochester Gas and Electric
RIM	Rate Impact Measure
RMM	Regulation Movement Multiplier
ROS	Rest of State
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCT	Societal Cost Test
SO_2	Sulfur dioxide
Staff	Staff of the New York State Department of Public Service
T&D	Transmission and Distribution
UCAP	Unforced Capacity
UCT	Utility Cost Test
VAR	Volt-ampere reactive
VVO	Volt/VAR Optimization
VSS	Voltage Support Services
WACC	Weighted Average Cost of Capital

2. Executive Summary

New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation (collectively the "Companies") submit this Benefit-Cost Analysis ("BCA") Handbook fulfilling a requirement of the Order Establishing the Benefit Cost Analysis Framework (BCA Order).[2] The BCA Framework included in Appendix C of the BCA Order is incorporated into this BCA Handbook.

Key to the development of this initial BCA Handbook is BCA Framework notations made in the February 26, 2015 Order Adopting Regulatory Policy Framework and Implementation Plan:

> "*A determination that since REV is a long term, far reaching initiative that will eventually touch most parts of the utilities' infrastructure and business practices, an attempt to project a quantified analysis on the wide-ranging set of potential benefits in a REV approach, against hypothetical future cost scenarios under both REV and conventional approaches, would be artificial and counter-productive and that such an effort would distract from the far more important task of carefully phasing the implementation of REV so that actual expenditures, when they occur, are considered intelligently in light of potential benefits recognizing that in this multi-phased implementation process, benefits and costs will be considered with increasing specificity*."

The Companies have prepared this initial BCA Handbook to provide a foundational methodology along with valuation assumptions to support a variety of utility programs and projects. This initial BCA Handbook is issued with the expectation that it will be revised and refined over time and as informed by: new opportunities that REV provides, experience gained from programs and project deployment, and experience gained from New York and the Companies transmission and distribution grid system enhancement.

This Handbook covers the following four categories of utility expenditures, as required per the BCA Order:[3]

1. Investments in distributed system platform (DSP) capabilities
2. Procurement of distributed energy resources (DER) through competitive selection[4]
3. Procurement of DER through tariffs[5]
4. Energy efficiency programs

This Handbook is prepared consistent with the BCA Order list of principles of the BCA Framework. These five principles stated that the BCA Handbook should:

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[2] BCA Order: Case 14-M-0101, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016).
[3] BCA Order, pgs. 1-2.
[4] Also known as non-wires alternatives (NWA).
[5] These may include, for example, demand response tariffs or successor tariffs to net energy metering.

1. Be based on transparent assumptions and methodologies; list all benefits and costs including those that are localized and more granular.
2. Avoid combining or conflating different benefits and costs.
3. Assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures).
4. Address the full lifetime of the investment while reflecting sensitivities on key assumptions.
5. Compare benefits and costs to traditional alternatives instead of valuing them in isolation.

Given these principles and framework guidance, the purpose of the Companies initial BCA Handbook is to provide the methodology for calculating benefits and costs of the Companies programs, projects and investments using the input assumptions as provided within and/or referenced to external sources.

The Companies BCA Handbook is consistent with the statewide methodologies adopted by the New York Joint Utilities (JU).

3. Application of the BCA Handbook

3.0 Assumptions, Scope and Approach

Evaluation of cost-effectiveness of programs, project and infrastructure investments is a complex undertaking which needs to consider many factors; some of which may be easier to quantify than others. It is important to understand that the analysis result is highly dependent on the base financial and framework assumptions that go into the assessment; including forecasting to estimate the future benefits and costs, performance, and cumulative impacts of changes to systems over time. Therefore, these key assumptions have been derived with transparency of structural parameters in mind.

The Companies BCA Handbook includes key assumptions, scope, and approach for a BCA. It also presents applicable BCA methodologies and describes how to calculate both the individual benefits and costs as well as the necessary cost-effectiveness tests as identified in the BCA Order.

This BCA Handbook discusses general BCA considerations and notable issues regarding data collection for impact assessments, describes the relevant cost-effectiveness tests and identifies the pertinent benefits and costs to be applied for each test. It also provides metric definitions and equations, along with key parameters and sources.

This BCA Handbook provides a common basis for BCA across investments in programs, projects and portfolios. Evaluation of DER or utility investment in DSP capabilities and project portfolios will require additional information and data that is specific to the program, project or portfolio being evaluated.

As applicable, this BCA Handbook denotes specifics of each type of utility spending to: programs (such as Energy Efficiency), projects (such as NWAs) and infrastructure investments (such as system-wide improvements).

As identified in each section following, the data provided in this BCA Handbook may consist of: common data that are applicable across New York, the Companies publically available utility-specific data as well as program, project or infrastructure investment data specific to project type and locational-specific data.

3.1 New York Data Sources

Common assumptions applicable across New York include: information publicly provided by the New York Independent System Operator (NYISO), information provided by the Department of Public Service (DPS) Staff directly in the BCA Order, and other common to New York information provided here in the handbook. Table 3-1 lists the source of the statewide data utilized for the purposes of this Handbook.

TABLE 3-1. NEW YORK ASSUMPTIONS

New York Assumptions	Source
Energy and Demand Forecast	NYISO: Load & Capacity Data[6]
Avoided Generation Capacity Cost (AGCC)	DPS Staff: ICAP Spreadsheet Model[7]
Locational Based Marginal Prices (LBMP)	NYISO: Congestion Assessment and Resource Integration Study Phase 2 (CARIS Phase 2)[8]
Historical Ancillary Service Cost	NYISO: Markets & Operations Reports[9]
Wholesale Energy Market Price Impacts	DPS Staff: To be provided[10]
Allowance prices (SO_2 and NO_X)	NYISO: CARIS Phase 2[11]
Net Marginal Damage Cost of Carbon	DPS Staff: To be provided[12]

[6] The 2016 Load & Capacity Data report is available in the Planning Data and Reference Docs folder at: http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

[7] The ICAP Spreadsheet Model is found under Case 14-M-0101 at the Commission's website: http://www.dps.ny.gov. The filename is BCA Att A Jan 2016.xlsm.

[8] The finalized annual and hourly from 2016 CARIS Phase 2 will be available in the CARIS Study Outputs folder within the Economic Planning Studies folder at: http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp. In the interim, work with DPS Staff on appropriate values to use for the ETIP filing.

[9] Historical ancillary service costs are available at: http://www.nyiso.com/public/markets_operations/market_data/custom_report/index.jsp. The values to apply are described in Section 7.1.5.

[10] DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year.

[11] The allowance price assumptions for the 2016 CARIS Phase 2 study will be available in the CARIS Input Assumptions folder within Economic Planning Studies at: http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp.

[12] DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year.

3.2 The Companies Data Sources

The Companies utility-specific data include that which is reported publicly by the NYPSC with utility-specific values, such as reliability metrics, or embedded in various utility published documents such as rate cases.

Table 3-2 lists the sources of the Companies publicly available utility-specific data for this BCA Handbook.

TABLE 3-2. UTILITY-SPECIFIC ASSUMPTIONS

Utility-Specific Assumptions	Source
Weighted Average Cost of Capital (WACC)	NYSEG: New York State Electric and Gas Case No. 15-E-0283, 15-G-0284 RG&E: Rochester Gas and Electric Corporation Case No. 15-E-0285, 15-G-0286
Transmission and Distribution System Line losses	NYSEG: NYSEG and RG&E T&D Losses 7/17/2008 Case 08-E-0751 RG&E: NYSEG and RG&E T&D Losses 7/17/2008 Case 08-E-0751
Marginal Cost of Service	NYSEG: NYSEG Marginal Cost of Electric Delivery Service 5/11/2015 filed in New York State Electric and Gas Case No. 15-E-0283 RG&E: Rochester Gas and Electric Corporation Marginal Cost of Electric Delivery Service 10/23/2015 filed in Rochester Gas and Electric Corporation Case No. 15-E-0285
Reliability metrics	NY DPS: Electric Reliability Performance Report, 2010-2014

The New York statewide and the Companies publicly available utility-specific assumptions that are included in this initial version of the BCA Handbook (as listed in Table 3-1 and Table 3-2) are typically values by zone or utility system averages. Future versions of the Companies Handbook may be enhanced and may include more refined granular data as it becomes available.

Examples of this type of more granular data include the following:

- Locational: circuit-specific, zonal, regional, equipment-specific
- Temporal: hourly, seasonal

The Companies utility-specific data that is not publically available is addressed later in this Handbook in Section 9.

3.3 Project, Program and Portfolio Discussion

The BCA methodology underlying the Companies BCA Handbook is technology-agnostic and should be broadly applicable to all anticipated project types with some necessary adjustments sensitive to purpose and project-specific siting.

This BCA Handbook provides transparent information to allow the Companies, DER developers, and others to develop their own BCA model/tools that will be used by the Companies and may be used by external parties to accommodate and evaluate a variety of different project types.

The Companies BCA models/tools may require and will allow use of project-specific information for both utility investments and alternative distributed energy resources (DER)[13] solutions. Therefore, project sponsors will need to provide project-specific assumptions to allow the Companies to model for its respective BCA.

For system planning purposes, the Companies BCA models/tools will leverage system average values or leverage generic resources or portfolios of resources as well as project-specific information.

The Companies BCA model/tool will consider the specific type of investment being assessed.

- For example, if the assessment is a DSP capability (e.g., system-wide improvements, volt-VAR optimization (VVO), and automated feeder switching), the applicable model elements may be different than (although consistent with) that used for a comparison of DER for non-wires alternative (NWA) investments.

BCA model/tools developed by the Companies will allow for portfolio, program, project and infrastructure investment analysis, including cost effectiveness tests: Societal Cost Test (SCT), Utility Cost Test (UCT) and Rate Impact Measures (RIM) as applicable.

Program, project and infrastructure investment analyses will be informed by the specifics of: each program type and measures contained within, project technologies including those containing multiple measures, locational siting, utility investment need or other factors.

[13] DER includes solar photovoltaics (PV), combined heat and power (CHP), energy storage (ES), energy efficiency (EE), and demand response (DR).

This information would be populated into the model or tool appropriate for the given project type to perform the final detailed analysis required for the cost test.

Table 3-3 presents example DER project-specific data which may be necessary for an NWA evaluation.

TABLE 3-3. EXAMPLE OF DER PROJECT-SPECIFIC DATA

Project-Specific Data
Nameplate capacity
Coincidence factor with system peak
Derating factor for generation
Coincidence factor with transmission peak
Derating factor for transmission
Coincidence factor for distribution
Derating factor for distribution
Energy impact
Installed cost
Operating cost
Lifetime

Other applications of the BCA Handbook would likely require a different set of data tailored-to-the- project-, program- or infrastructure investment data applicable to type and need.

4. Structure of the Handbook

This document contains four sections explaining the methodology and assumptions used to perform a BCA.

Section 5. General Methodological Considerations describes key issues and challenges that are addressed in this BCA Handbook and that should be considered when developing project-specific BCA models and tools based on this BCA Handbook.

Section 6. Relevant Cost-Effectiveness Tests defines each cost effectiveness test included in the BCA Framework. These include the Societal Cost Test (SCT), the Utility Cost Test (UCT), and the Rate Impact Measure (RIM). The BCA Order specifies the SCT as the primary measure of cost effectiveness.

Section 7. Benefits and Costs Methodology provides detailed definitions, calculation methods, and general considerations for each benefit and cost.

Section 8. Characterization of DER Profiles discusses which benefits and costs are likely to apply to different types of DER, and provides examples for a sample selection of DERs.

Section 9. Utility-Specific Data includes NYSEG and RG&E value assumptions to be applied to quantifiable energy and non-energy impacts of projects, programs and portfolios.

5. General Methodological Considerations

5.0 Overview of Key Issues

This section describes key issues and challenges that are addressed in this initial BCA Handbook and that should be considered when developing project, program or portfolio-specific BCAs based on the methodology identified in the BCA Handbook.

Benefits and Costs for projects, programs and portfolios may be derived from the technologies deployed; each with technology-specific benefits delivered and costs associated to do so. Careful consideration of the project, program and portfolio must be given to properly parse out these details, on both the benefit and cost side, to allow determination of inputs without co-inflating, overlapping or discounting benefits or costs in error. Quantifying the impacts of a technology within the project, program or portfolio is an important initial step; assignment of valuation and monetizing the benefits, as well as identification of the associated costs follows the initial quantification.

Projects may provide more than the easily identified direct benefits and associated costs. Some technologies may additionally enable and/or enhance the benefits of other technologies contained within the full project scope, and thereby result in additional benefits though this parallel function. Therefore, for complex projects, consideration should be given to technologies which may not result in realization of only the directly applicable benefits, but also those which either independently or in conjunction with the array of project offerings may function to enable or facilitate the realization of benefits from additional measures or technologies.

- It is important not to over- or under-count benefits resulting from multiple measures or technologies functioning together to achieve an impact.
- Determination of which impacts and benefits are derived from which investment elements will often depend on how and/or in what order the elements are implemented.

Program and Portfolio assessments need to be considered in a holistic manner to be properly assessed. Benefits and costs should also be allocated properly across different projects and programs that are contained with the portfolio to be assessed. This may present challenges; especially in the case of enabling and enhancing technologies.

Enabling technologies such as an advanced distribution management system or a communications infrastructure are often crucial in achieving the impact and benefits of grid modernization projects. These infrastructure investments may be necessary for the implementation of other technologies, projects, or programs, and in some cases the same investments could also enable a given asset to achieve additional benefits beyond what that asset may have been able to achieve on its own. Over time, investments made as part of previous projects or portfolios may also enable or enhance new projects. The BCA Order states that utility BCA shall consider incremental T&D costs "to the extent that the characteristics of a project cause additional costs to be incurred."[14]

Multiple technologies may result in impacts that produce the same benefits.

- For example, there are many ways in which distribution grid modernization investments could affect the frequency and duration of sustained outages. Advanced meters equipped with an outage notification feature, an outage management system, automated distribution feeder switches or reclosers, and remote fault indicators are some examples of technologies that could all reduce the frequency or duration of outages on a utility's distribution network and result in Avoided Outage Cost or Avoided Restoration Cost benefits.

The BCA must also address the non-linear nature of grid and DER project benefits.

- For example, impact on Avoided Distribution Capacity Infrastructure of an energy storage project may be capped based on the interconnected load on the given feeder. If there is 1 MW of potentially deferrable capacity on a feeder with a new battery storage system, installation of a 5-MW storage unit will not result in a full 5 MW-worth of capacity deferral credit for that feeder.
- As another example, the incremental improvement on reliability indices may diminish as more automated switching projects are in place.

5.1 Benefit Definitions and Differentiation

A key consideration identified in performing a BCA is to perform proper accounting of benefits and costs, including avoidance of under- or over-counting. This is done by appropriately defining each benefit and cost.

Section 6 below identifies the 16 benefits to be included in the cost-effectiveness tests per the BCA Order. The calculation methodology for each of these benefits is provided in Section 7.

As discussed in detail above, the BCA should be constructed to consider potentially overlapping benefits. In general, this means that for each potential benefit in a project or portfolio investment, care must be taken that different technologies, or even multiple instances of the same technology, do not interact to change the impact calculation for that benefit, or that the interactive effects are explicitly considered in the calculation.

- For example, an energy efficiency measure and a demand response technology deployed in a portfolio could both reduce system co-incident capacity, but together their

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[14] BCA Order, Appendix C pg. 18.

combined impact is likely to be less than if each is calculated independently. It is important to consider these interactive affects to avoid double counting of benefits.

The BCA analysis should be constructed to consider potentially overlapping costs. Some types of costs may be potentially leveraged across different projects or portfolios.

- For example, investment in a communications infrastructure for monitoring DER performance could be shared across multiple DER installations and multiple applications. In these cases cost allocations need to be made across projects or portfolios to appropriately consider these shared costs in the analysis.

Two benefits defined in the BCA Order; bulk system benefits Avoided Generation Capacity Costs (AGCC) and Avoided Locational Based Marginal Price (LBMP) result from system coincident peak demand reduction and energy reduction impacts respectively, with avoided cost values derived from multiple components. These impacts and embedded component values included in the AGCC and Avoided LBMP benefits may be confused with other benefits identified in the BCA Order that must be calculated separately.

These key potentially overlapping benefits deserve additional explanation, which is provided in Table 5-1 and the bullets following:

TABLE 5-1. BENEFITS WITH POTENTIAL OVERLAPS

Main Benefit	Overlapping Benefit
Avoided Generation Capacity Costs, or ICAP, including Reserve Margin	• Avoided Transmission Capacity • Avoided Transmission Losses • Avoided Distribution Losses*
Avoided LBMP	• Net Avoided CO_2 • Net Avoided SO_2 and NO_x • Avoided Transmission Losses • Avoided Transmission Capacity • Avoided Distribution Losses

- Avoided transmission and distribution loss impacts resulting from energy and demand reductions that should be included in the calculations of the AGCC and Avoided LBMP; it is important to differentiate them from the impacts that should be counted as separate Avoided Transmission Losses and Avoided Distribution Losses benefits.
- Differentiation between the transmission capacity values embedded as components of the AGCC and Avoided LBMP values, as well as differentiation between the CO_2, SO_2, and NO_x values embedded in Avoided LBMP values and those values that must be

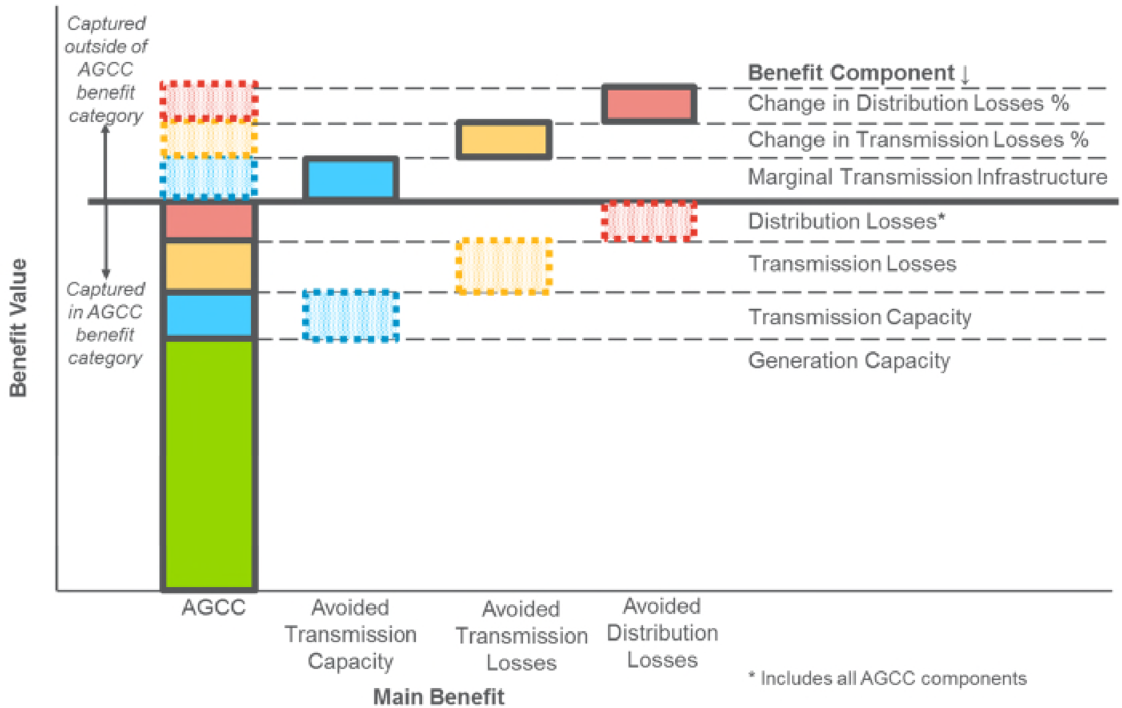
applied separately in the Net Avoided CO_2 and Net Avoided SO_2, and NO_x benefits calculations must be considered.

5.1.1 Benefit Overlapping with Avoided Generation Capacity Costs

AGCC assumptions used by the NYISO to calculate the AGCC values as captured in the AGCC benefit category; which are subsequently used by the DPS Staff in the ICAP Spreadsheet Model include benefits from sources other than Generation Capacity. In the figure below, components identified below the line depict all benefit values as captured in the AGCC benefit category; which include additional benefits from Transmission Capacity, and Transmission and Distribution Loss assumptions.

These components below the line must be identified discretely and then their effects removed from the NYISO AGCC assumption in order to provide a base from which to build in the actual impacts that locational and/or project specific values supply. In the figure below, components identified above the line depict locational and/or project specific benefits; which will be built into the values considered within the BCA assessment.

FIGURE 5.1 BENEFITS POTENTIALLY OVERLAPPING WITH AVOIDED GENERATION CAPACITY COSTS (ILLUSTRATIVE)



To further explain; in this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts excluded from the main benefit, but included in calculation of a separate benefit. The benefit shown above, Avoided Generation Capacity Costs, includes multiple components that are captured in the AGCC value. These include – ICAP including reserve margin, transmission capacity, and transmission tosses.[15] Additionally, distribution losses can affect the calculation of AGCC, depending on the project location on the system.[16] The AGCC calculation accounts for these distribution losses.

If a project changes the electrical topology and therefore changes the transmission loss percent itself, the incremental changes in transmission losses would be allocated to the Avoided Transmission Losses benefit. Similarly, any incremental changes to distribution loss percent as a result of the project would be included in the Avoided Distribution Losses benefit. These benefits are calculated separately from the AGCC benefit.

[15] The AGCC includes a portion of avoided transmission capacity infrastructure costs as zonal differences in the ICAP clearing price.

[16] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the AGCC due to higher losses.

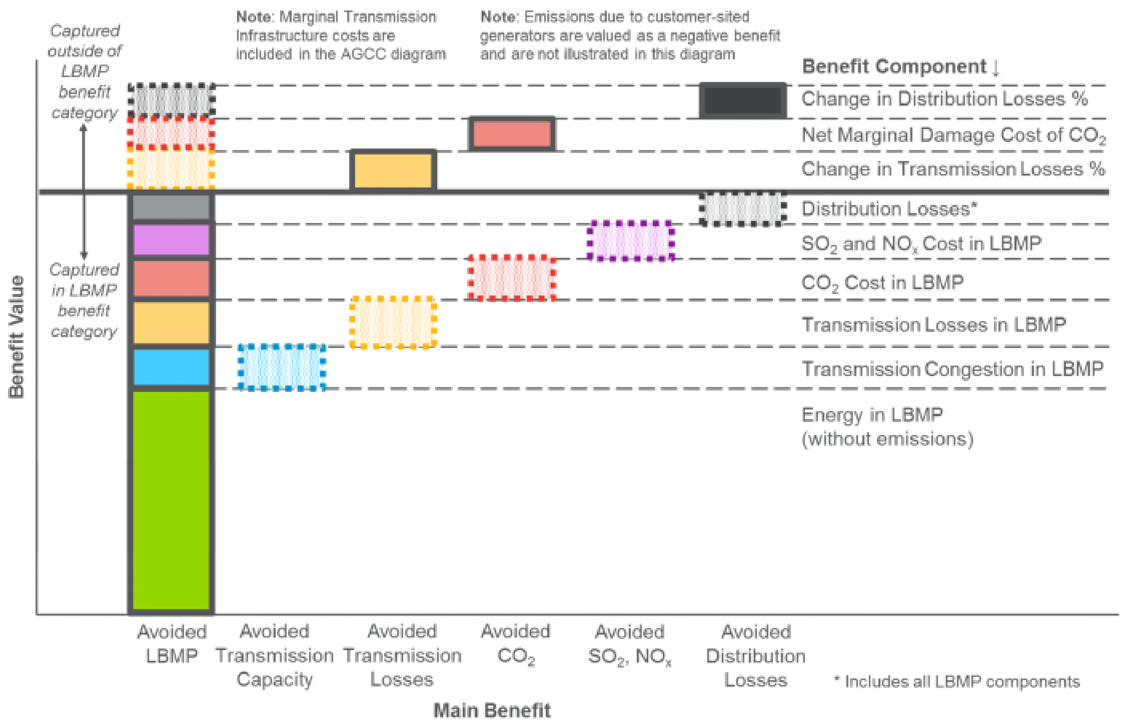
5.1.2 Benefits Overlapping with Avoided LBMP

Avoided LBMP assumptions used by the NYISO to calculate the LBMP values as captured in the LBMP benefit category, which are subsequently used by the DPS Staff in the ICAP Spreadsheet Model include benefits from sources other than Energy in LBMP. In the figure below, components identified below the line depict all benefit values as captured in the LBMP benefit category; which include additional benefits from Transmission Congestion, Transmission and Distribution Losses, and CO_2, SO_2 and NO_x Costs.

These components below the line must be identified discretely and then their effects removed from the NYISO LBMP assumption in order to provide a base from which to build in the actual impacts that locational and/or project specific values supply. In the figure below, components identified above the line depict locational and/or project specific benefits; which will be built into the values considered within the BCA assessment.

Figure 5-2 graphically illustrates potential overlaps of benefits pertaining to Avoided LBMP.

FIGURE 5.1. BENEFITS POTENTIALLY OVERLAPPING WITH AVOIDED LBMP BENEFIT (ILLUSTRATIVE)



To further explain: in this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts excluded from the main benefit, but included in calculation of a separate benefit. As seen in the figure, the stacked solid boxes in the Avoided LBMP benefit include costs for factors beyond simple energy cost per megawatt-hour (MWh) of the electricity traded in the wholesale energy market. The following are included in the Avoided LBMP benefit:

- Avoided transmission capacity infrastructure costs built into the transmission congestion charge which are embedded in the LBMP
- Transmission-level loss costs which are embedded in the LBMP

Compliance costs of various air pollutant emissions regulations including the value of CO_2 via the Regional Greenhouse Gas Initiative and the values of SO_2 and NO_x via cap-and-trade markets which are embedded in the LBMP

Additionally, distribution losses can affect LBMP purchases, depending on the project location on the system, and should gross up the calculated LBMP benefits.[17] To the extent a project changes the electrical topology and changes the distribution loss percent itself, the incremental changes in distribution losses would be allocated to the Avoided Distribution Losses benefit. Similarly, there may be projects that would specifically impact Avoided Transmission Capacity or change the transmission loss percent. In these instances, the impacts would be captured outside of the Avoided LBMP benefit.

5.2 Incorporating Losses into Benefits

Many of the benefit equations provided in Section 7 include a parameter to account for losses. In calculating a benefit or cost resulting from load impacts, the variable losses occurring upstream from the load impact must be accounted for to arrive at the total energy or demand impact. Losses can be accounted for either by adjusting the impact parameter or the valuation parameter. For consistency, all equations in Section 7 are shown with a loss adjustment to the impact parameter.

The following losses-related nomenclature is used in the BCA Handbook:

- **Losses (MWh or MW)** are the difference between the total electricity send-out and the total output as measured by revenue meters. This difference includes technical and non-technical losses. Technical losses are the losses associated with the delivery of electricity of energy and have fixed (no load) and variable (load) components. Non-technical losses represent electricity that is delivered, but not measured by revenue meters,

[17] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the LBMP purchases due to higher losses.

- **Loss Percent (%)** are the total fixed and/or variable[18] quantity of losses between relevant voltage levels divided by total electricity send-out, unless otherwise specified.
- **Loss Factor (dimensionless)** is a conversion factor derived from "loss percent". The loss factor is 1 / (1 - Loss Percent).

For consistency, the equations in Section 7 follow the same notation to represent various locations on the system:

- "r" subscript represents the retail delivery point or point of connection of a DER to the distribution network.
- "w" subscript represents the wholesale delivery point, or the interface between the transmission system and the distribution system. This is the location on the system that the LBMP is based upon.
- "b" subscript represents the bulk system generation point, also referred to as the generation busbar. This is the location on the system directly upstream of the transmission system.

Based on the notation described above, if a residential customer is connected to distribution secondary the loss percent parameter called $\mathrm{Loss\%}_{\mathrm{b}\rightarrow\mathrm{r}}$ would represent the loss percent between the bulk system ("b") and the retail delivery or connection point ("r"). In this example, the loss percent would be the sum of the distribution secondary, distribution primary and transmission loss percentages. If a large commercial customer is connected to primary distribution the appropriate loss percent would be the sum of distribution primary and transmission loss percentages.

5.3 Establishing Credible Baselines

One of the most significant challenges associated with evaluating the benefit of a grid or DER project or program is establishing baseline data that illustrates the performance of the system without the project or program. The utility may derive baseline estimates from recent historical data, forecasts, statistical or model-based projections, or comparison/control groups (e.g., similar feeders and households) during the course of the project.

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[18] In the BCA equations outlined in Section 7 below, project-specific energy and demand impacts at the retail delivery point are adjusted to the bulk system (or other relevant system location) based on *only* the variable component of the loss percent. In cases where the transmission or distribution loss percent is altered due to a project, the fixed and/or variable loss percent impacts are considered.

Sound baseline data is crucial in measuring the incremental impact of the technology deployment. Because benefits of grid modernization projects accrue over many years, baselines must be valid across the same time horizon. This introduces a few points that merit consideration:

- **Forecasting market conditions**: Project impacts as well as benefit and cost values are affected by market conditions. For example, the Commission has directed that Avoided LBMP should be calculated based on NYISO's CARIS Phase 2 economic planning process base case LBMP forecast. However, the observed benefit of a project will be different if the wholesale energy market behaves differently from the forecasted trends.[19]
- **Forecasting operational conditions**: Many impacts and benefits are tied to how the generation, transmission, and distribution infrastructure are operated. In this example, the Commission indicated that benefits associated with avoided CO_2 emissions shall be based on the change in the tons of CO_2 produced by the bulk system when system load levels are reduced by 1%. It is important to note that this impact calculation is an approximation and it is still very difficult to determine the actual CO_2 reductions at the bulk system level from the impacts of projects implemented at the distribution system level. Project-specific reductions are tied to dispatch protocols based on the optimized operation of the bulk system given a set of preventive post-contingency settings. In addition, the carbon intensity of the generation mix will inevitably change over time independent of any investment at the distribution level.
- **Predicting asset management activities**: Some impacts and benefits, such as Avoided Distribution Capacity Infrastructure, are affected by distribution-level capital investments that may take place independent of the projects being evaluated. In this example, the amount of available excess capacity may change if key distribution assets are replaced and uprated.

There are significant uncertainties surrounding the benefits and costs. Regulatory approvals, technological advances, operational budgets, and other business conditions all affect the cost of deployment, expected system performance, or both. As such, the utility may re-evaluate and revise its baseline data as significant events or developments alter the assumed or implied conditions underlying the existing baseline..

[19] Long-term forecasts include sensitivity analyses. See, for example, the 2015 CARIS (http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp) and Clean Energy Standard White Paper – Cost Study (April 2016, filed under NYPSC Case Number 15-E-0302) for further discussion of price forecast sensitivities.

5.4 Normalizing Impacts

In addition to establishing an appropriate baseline, normalizing impact data presents similar challenges. This is particularly true for distribution-level projects, where system performance is significantly affected by external conditions beyond that which occurs on the distribution system. For instance, quantifying the impact of technology investment on reliability indices would require the baseline data to be representative of expected feeder reliability performance. This is a challenging task, as historical data would require weather adjustments and contemporaneous data would be drawn from different, but similar, feeders.

A distribution feeder may go through changes that could influence feeder performance independent of the technologies implemented. For instance, planned outages due to routine maintenance activities or outages due to damages from a major storm could impact reliability indices and changes in the mix of customer load type (e.g., residential vs. commercial and industrial), which may impact feeder peak load.

5.5 Establishing Appropriate Analysis Time Horizon

The duration over which the impact and benefits of new grid and DER investments accrue varies significantly. The time horizon for the analysis must consider several factors, including differences among the lengths of expected useful life of various hardware and software across multiple projects and how to reconcile the differences in these lengths of expected useful lives. The analysis timeframe should be based on the longest asset life included in the portfolio/solution under consideration.[20]

5.6 Granularity of Data for Analysis

The most accurate assumptions to use for assessing a BCA would leverage suitable location or temporal information. When the more granular data is not available, an appropriate annual average or system average maybe used, if applicable in reflecting the expected savings from use of DER.

More granular locational or temporal assumptions are always preferred to more accurately capture the savings from use of a resource. However, the methodology included in the BCA Handbook would accommodate appropriate system averages in cases where their use is required.

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[20] *BCA Order*, pg. 2

5.7 Performing Sensitivity Analysis

The BCA Order indicates that the BCA Handbook shall include "description of the sensitivity analysis that will be applied to key assumptions."[21] As Section 7 presents, there is a discussion of each of the benefits and costs, and a sensitivity analysis can be performed by changing selected parameters.

The largest benefits for DER are typically the bulk system benefits of Avoided LBMP or AGCC. For example:

- A sensitivity of LBMP, $/MWh, could be based on alternative wholesale market studies.[22]
- Annual average LBMPs could be compared across studies to scale time-differentiated LBMPs.

In addition to adjusting the values of an individual parameter as a sensitivity; the applicability of certain benefits and costs would be considered as a sensitivity analysis of the cost-effectiveness tests. For example:

- Inclusion of the Wholesale Market Price Impacts in the UCT and RIM would be assessed as a sensitivity.[23]

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[21] *BCA Order*, Appendix C, pg. 31.

[22] Long-term forecasts include sensitivity analyses. See, for example, the 2015 CARIS (http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp) and Clean Energy Standard White Paper – Cost Study (April 2016, filed under NYPSC Case Number 15-E-0302) for further discussion of price forecast sensitivities.

[23] *BCA Order*, pg. 25 ("The evaluation would then be conducted showing separately the impacts both with and without the wholesale market price effect.")

6. Relevant Cost-Effectiveness Tests

6.0 Overview of Cost-Effectiveness Tests

The BCA Order states that the SCT, Utility Cost Test (UCT), and the Rate Impact Measure (RIM) make up the relevant cost-effectiveness tests to be used in the BCA. These cost-effectiveness tests are summarized in Table 6-1.

TABLE 6-1 COST-EFFECTIVENESS TESTS

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions and other net non-energy benefits)
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The BCA Order positions the SCT as the primary cost-effectiveness measure because it evaluates impact on society as a whole.

The role of the UCT and RIM is to assess the preliminary impact on utility costs and ratepayer bills from the benefits and costs that pass the SCT. The results of the UCT and RIM test are critical in identifying projects that may require a more detailed analysis of their impact to the utility and ratepayers. Some projects may not provide benefits to the utility and ratepayers, even if it is beneficial to society as a whole.

It is important to note, however, that if a measure passes the SCT but its results do not satisfy the UCT and RIM tests, the measure would not be rejected unless a complete bill impact analysis determines that the impact is of a “magnitude that is unacceptable”.[24]

Each cost-effectiveness test included in the BCA Framework is defined in greater detail in the following subsections. Which of the various benefits and costs to include in analysis of individual projects or investment portfolios requires careful consideration, as discussed in Section 5.

[24] *BCA Order*, pg. 13.

6.1 Summary of Cost Effectiveness Tests

Table 6-2 summarizes which cost-effectiveness tests can be applied to the benefits and costs included in the BCA Order. The sub-sections below provide further context for each cost-effectiveness test.

TABLE 6-2. SUMMARY OF COST-EFFECTIVENESS TESTS BY BENEFIT AND COST

Section #	Benefit/Cost	SCT	UCT	RIM
Benefit				
7.1.1	Avoided Generation Capacity Costs†	✓	✓	✓
7.1.2	Avoided LBMP‡	✓	✓	✓
7.1.3	Avoided Transmission Capacity Infrastructure†‡	✓	✓	✓
7.1.4	Avoided Transmission Losses†‡	✓	✓	✓
7.1.5	Avoided Ancillary Services*	✓	✓	✓
7.1.6	Wholesale Market Price Impacts**		✓	✓
7.2.1	Avoided Distribution Capacity Infrastructure	✓	✓	✓
7.2.2	Avoided O&M	✓	✓	✓
7.2.3	Avoided Distribution Losses†‡	✓	✓	✓
7.3.1	Net Avoided Restoration Costs	✓	✓	✓
7.3.2	Net Avoided Outage Costs	✓		
7.4.1	Net Avoided CO_2‡	✓		
7.4.2	Net Avoided SO_2 and NO_x‡	✓		
7.4.3	Avoided Water Impacts	✓		
7.4.4	Avoided Land Impacts	✓		
7.4.5	Net Non-Energy Benefits***	✓	✓	✓

Cost				
7.5.1	Program Administration Costs	✓	✓	✓
7.5.2	Added Ancillary Service Costs*	✓	✓	✓
7.5.3	Incremental T&D and DSP Costs	✓	✓	✓
7.5.4	Participant DER Cost	✓		
7.5.5	Lost Utility Revenue			✓
7.5.6	Shareholder Incentives		✓	✓
7.5.7	Net Non-Energy Costs**	✓	✓	✓

† See Section 5.1.1 for discussion of potential overlaps in accounting for these benefits.
‡ See Section 5.1.2 for discussion of potential overlaps in accounting for these benefits.

** The amount of DER is not driver of the size of NYISO's Ancillary Services markets since a change in load will not result in a reduction in the NYISO requirements for Regulation and Reserves as the requirements for these services are set periodically by NYISO to maintain frequency and to cover the loss of the largest supply element(s) on the bulk power system. Therefore, there is no impact within the SCT as the overall Ancillary Services requirement remains unchanged.*

*** The Wholesale Market Price Impacts in the UCT and RIM would be assessed as a sensitivity.*
**** It is necessary to identify which cost-effectiveness test should include the specific benefit or cost in the Net Non-Energy Benefit or Net Non-Energy Cost as it may apply to the SCT, UCT and/or RIM.*

Performing a cost-effectiveness test for a specific project or a portfolio of projects requires the following steps:

- **Select the relevant benefit** for the investment.
- **Determine the relevant costs** from each cost included over the life of the investment.
- **Estimate the impact** the investment will have in each of the relevant benefits in each year of the analysis period (i.e., how much will it change the underlying physical operation of the electric system to produce the benefits).
- **Apply the benefit values** associated with the project impacts as described in Section 7.
- **Apply the appropriate discount rate** to perform a cost-effectiveness test for a specific project or portfolio. The discount rate is the utility weighted average cost of capital to determine the present value of all benefits and costs.
- **Treat inflation consistently** by discounting real cash flow by real discount rates and nominal cash flows by nominal discount rates. A 2% annual inflation rate should be assumed unless otherwise specified.

6.2 Societal Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions, and net non-energy benefits)

A majority of the benefits included in the BCA Order can be evaluated under the SCT because their impact can be applied to society as a whole. This includes all distribution system benefits, all reliability/resiliency benefits, and all external benefits.

Lost Utility Revenue and Shareholder Incentives do not apply to the SCT, as these are considered transfers between stakeholder groups that have no net impact on society as a whole.

Similarly, the Wholesale Market Price Impact sensitivity is not performed for the SCT because the price suppression is also considered a transfer from large generators to market participants in the BCA Order:

> "Wholesale markets already adjust to changes in demand and supply resources, and any resource cost savings that result are reflected in the SCT. Any price suppression over and above those market adjustments is essentially a transfer payment -- simply a shift of monetary gains and losses from one group of economic constituents to another. No efficiency gain results if, for example, generators are paid more or less while consumers experience equal and offsetting impacts. Therefore, the price suppression benefit is not properly included in the SCT beyond the savings already reflected there."[25]

[25] BCA Order, pg. 24

6.3 Utility Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs

The UCT looks at impact to utility costs associated with energy, capacity, generation, T&D, overhead, and general and administrative. For this reason, external benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts do not apply to the UCT. Utilities in New York do not currently receive incentives for decreased CO_2 or other environmental impacts. Benefits related to avoided outages would go to customers and not utilities, so this benefit also does not apply to the UCT.

Participant DER Cost and Lost Utility Revenue are not considered in the UCT because the cost of the DER is not a utility cost and any reduced revenues from DER are made-up by non-participating DER customers through the utility's revenue decoupling mechanism or other means.

6.4 Rate Impact Measure

Cost Test	Perspective	Key Question Answered	Calculation Approach
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The RIM test can address rate impacts to non-participants. External benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts do not apply to the RIM as they do not directly affect customer rates. Benefits related to avoided outages go to customers but, again, would have no effect on rates.

Participant DER cost does not apply to the RIM because the cost of the DER is not a utility cost. However, any reduced revenues from DER are included as increased costs to other ratepayers as Lost Utility Revenue because of revenue decoupling or other means that transfer costs from participants to non-participants

7. Benefits and Costs Methodology

7.0 Overview of Benefit-Cost Categories

Each subsection below aligns with a benefit or cost listed in the BCA Order. Each benefit and cost stream includes a definition, equation, and general considerations.

There are four types of benefits which are further explained in the sub-sections below:

- **Bulk System** – larger system responsible for the generation, transmission and control of electricity passed on to the local distribution system.
- **Distribution System** – system responsible for the local distribution of electricity.
- **Reliability/Resiliency** – efforts made to reduce duration and frequency of outages.
- **Externalities** – consideration of social values for incorporation in the SCT.

Additionally, there are four types of costs that are also considered in the BCA framework and explained in the sub-sections below. They are:

- **Program Administration** – includes the cost of state incentives, measurement and verification, and other program administration costs to start-up and maintain a specific program
- **Utility-related** – those incurred by the utility such as incremental T&D, DSP, lost revenues and shareholder incentives
- **Participant-related** – those incurred to achieve project or program objectives,
- **Societal** – external costs for incorporation in the SCT

In this version of the Handbook, for energy, operational, and reliability-related benefits and costs,[26] it is assumed that impacts generate benefits/costs in the same year as the impact. In other words, there is no time delay between impacts and benefits/costs.

[26] Energy, operational, and reliability-related benefits and costs include: Avoided LBMP, the energy component of Avoided Transmission Losses, Avoided Ancillary Services, the energy portion of Wholesale Market Price Impact, Avoided O&M, Avoided Distribution Capacity Infrastructure, Net Avoided Restoration Costs, Net Avoided Outage Costs, the energy component of Distribution Losses, Net Avoided CO_2, Net Avoided SO_2 and NO_x, Avoided Water Impact, Avoided Land Impact, Net Non-Energy Benefits Related to Utility or Grid Operations, Program Administration Costs, Participant DER Cost, Lost Utility Revenue, Shareholder Incentives, and Net Non-Energy Costs.

However, for capacity and infrastructure[27] it is assumed that impacts generate benefits/costs in the following year of the impact. For example, if a project reduces system peak load in 2016, the AGCC benefit would not be realized until 2017.

7.1 Bulk System Benefits

7.1.1 Avoided Generation Capacity Costs

Avoided Generation Capacity Costs are due to reduced coincident system peak demand. This benefit is calculated by NYISO zone, which is the most granular level for which AGCC are currently available.[28] It is assumed that the benefit is realized in the year following the peak load reduction impact.

7.1.1.1 Benefit Equation, Variables, and Subscripts

Equation 7-1 presents the benefit equation for Avoided Generation Capacity Costs. This equation follows "Variant 1" of the Demand Curve savings estimation described in the 2015 Congestion Assessment and Resource Integration Study (CARIS) Appendix. Each NYISO zone is mapped to one of the four NYISO localities as follows: ROS = A-F, LHV = G-I, NYC = J, LI = K.

EQUATION 7-1. AVOIDED GENERATION CAPACITY COSTS

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \frac{\Delta \mathrm{PeakLoad}_{Z,Y,r}}{1\text{-}\mathrm{Loss\%}_{Z,Y,b \to r}} * \mathrm{SystemCoincidenceFactor}_{Z,Y} * \mathrm{DeratingFactor}_{Z,Y} * \mathrm{AGCC}_{Z,Y,b}$$

The indices of the parameters in 7-1 Avoided Generation Capacity Costs include:

- Z = NYISO zone (A → K)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

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[27] Capacity, infrastructure, and market price-related benefits and costs include: Avoided O&M, the capacity component of Avoided Transmission Losses, Avoided O&M, the capacity component of Distribution Losses, Avoided Transmission Capacity Infrastructure and Related O&M, the capacity potion of the Wholesale Market Price Impact, , Added Ancillary Service Costs, and Incremental Transmission & Distribution and DSP Costs.

[28] For a portfolio of projects located within multiple NYISO zones, it may be necessary to calculate weighted average across zones to obtain a benefit value.

$\mathbf{\Delta PeakLoad_{Z,Y,r}}$ **(∆MW)** is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"), by zone if applicable. This input is project or program specific. A positive value represents a reduction in peak load.

$\mathbf{Loss\%_{Z,b\rightarrow r}}$ **(%)**is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Section 9.

$\mathbf{SystemCoincidenceFactor_{Z,Y}}$ **(dimensionless)** captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability. For example, a nameplate demand reduction capacity of 100 kW with a system coincidence factor of 0.8 would reduce the bulk system peak demand by 80 kW. This input is project specific.

$\mathbf{DeratingFactor_{Z,Y}}$ **(dimensionless)** is presented here as a factor to de-rate the coincident peak load reduction based on the availability of a resource during system peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to system peak load reduction. This input is project specific.

$\mathbf{AGCC_{Z,Y,b}}$ **($/MW-yr)** represents the annual AGCCs at the bulk system ("b") based on forecast of capacity prices for the wholesale market provided by DPS Staff. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level" based on capacity obligations for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr. AGCC costs are calculated based on the NYISO's capacity market demand curves, using supply and demand by NYISO zone, Minimum Locational Capacity Requirements (LCR), and the Reserve Margin.

7.1.1.2 General Considerations

The AGCC forecast provided by Staff is based on capacity market demand curves using the demand forecasts and available supply from NYISO's Load & Capacity Data report. CARIS can be used for guidance on how demand curves are applied to the AGCC forecast.[29] The Reserve Margin is determined annually by New York State Reliability Council. Minimum LCR, set by

[29] 2015 CARIS Phase 1 Study Appendix. http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_(CARIS)/CARIS_Final_Reports/2015_CARIS_Final_Appendices_FINAL.pdf

NYISO, are applicable to several localities (NYC, LI, “G-J” Region) and account for transmission losses. See NYISO Installed Capacity Manual[30] for more details on ICAP.

AGCC benefits are calculated using a static forecast of AGCC prices provided by Staff. Any wholesale market capacity price suppression effects are not accounted for here and instead are captured in Wholesale Price Impacts, described in Section 7.1.6.

Impacts from a measure, project, or portfolio must be coincident with the system peak and accounted for losses prior to applying the AGCC valuation parameter. The “nameplate” impact (i.e. $\Delta PeakLoad_{Z,Y,r}$) should also be multiplied by a coincidence factor and derating factor to properly match the planning impact to the system peak. The coincident factor quantifies a project’s contribution to system peak relative to its nameplate impact.

It is also important to consider the persistence of impacts in future years after a project’s implementation. For example, participation in a demand response program may change over time. Also, a peak load reduction impact will not be realized as a monetized AGCC benefit until the year following the peak load reduction, as capacity requirements are set by annual peak demand and paid for in the following year.

The AGCC values provided in Staff’s ICAP Spreadsheet Model account for the value of transmission losses and infrastructure upgrades. In instances where projects change the transmission topology, incremental infrastructure and loss benefits not captured in the AGCC values should be modeled and quantified in the Avoided T&D Losses and Avoided T&D Infrastructure benefits, below.

7.1.2 Avoided LBMP

Avoided LBMP is avoided energy purchased at the Locational Based Marginal Price (LBMP). The three components of the LBMP (i.e., energy, congestion, and losses) are all included in this benefit. See Section 5.1.2 for details on how the methodology avoids double counting between this benefit and others. .

7.1.2.1 Benefit Equation, Variables, and Subscripts

Equation 7-2 presents the benefit equation for Avoided LBMP:

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30 http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf

EQUATION 7-2. AVOIDED LBMP

$$\text{Benefit}_{\text{Y}} = \sum_{\text{Z}} \sum_{\text{P}} \frac{\Delta\text{Energy}_{\text{Z,P,Y,r}}}{1 - \text{Loss\%}_{\text{Z,b}\rightarrow\text{r}}} * \text{LBMP}_{\text{Z,P,Y,b}}$$

The indices of the parameters in Equation 7-2 include:

- Z = zone (A → K)
- P = period (e.g., year, season, month, and hour)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\mathbf{\Delta Energy_{Z,P,Y,r}}$ **(ΔMWh)** is the difference in energy purchased at the retail delivery or connection point ("r") before and after project implementation, by NYISO zone and by year with by time-differentiated periods, for example, annual, seasonal, monthly, or hourly as appropriate. This parameter represents the energy impact at the project location and is **not** yet grossed up to the LBMP location based on the losses between those two points on the system. This adjustment is performed based on the $Loss\%_{Z,b\rightarrow r}$ parameter. This input is project- or program-specific. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Z,b\rightarrow r}}$ **(%)** is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in in Section 9

$\mathbf{LBMP_{Z,P,Y,b}}$ **($/MWh)** is the Locational Based Marginal Price, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). NYISO forecasts 20-year annual and hourly LBMPs by zone. To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

7.1.2.2 General Considerations

Avoided LBMP benefits are calculated using a static forecast of LBMP. Any wholesale market price changes as a result of the project or program are not accounted for in this benefit, and are instead captured in Wholesale Market Price Impacts, described in Section 7.1.6.

The time differential for subscript P (period) will depend on the type of project, and could be season, month, day, hour, or any other interval. The user must ensure that the time-differentiation is appropriate for the project being analyzed. For example, it may be appropriate to use an annual average price and impact for a DER that has a consistent load reduction at all hours of the year. However, using the annual average may not be appropriate for energy storage which may be charging during non-peak hours and discharging during peak hours. In that case, it may be appropriate to multiply an average on-peak (or super-peak) and off-peak LBMP by the on-peak (or super-peak) and off-peak energy impacts, respectively.

It is important to consider the trend (i.e., system degradation) of impacts in future years after a project's implementation. For example, a PV system's output may decline over time. It is assumed that the benefit is realized in the year of the energy impact.

7.1.3 Avoided Transmission Capacity Infrastructure and Related O&M

Avoided Transmission Capacity Infrastructure and Related O&M benefits result from location-specific load reduction that are valued at the marginal cost of equipment that is avoided or deferred by a DER project or program. A portion of Avoided Transmission Capacity is already captured in the congestion charge of the LBMP and the AGCC prices. Because static forecasts of LBMPs and AGCC values are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the planned transmission system investments from that level embedded in those static forecasts.

7.1.3.1 Benefit Equation, Variables, and Subscripts

Equation 7-3 presents the benefit equation for Avoided Transmission Capacity Infrastructure and Related O&M:

EQUATION 7-3. AVOIDED TRANSMISSION CAPACITY INFRASTRUCTURE AND RELATED O&M

$$\mathrm{Benefit}_{Y+1} = \sum_{C} \frac{\Delta \mathrm{PeakLoad}_{Y,r}}{1 - \mathrm{Loss\%}_{Y,b\rightarrow r}} * \mathrm{TransCoincidentFactor}_{C,Y} * \mathrm{DeratingFactor}_{Y} * \mathrm{MarginalTransCost}_{C,Y,b}$$

The indices[31] of summation for Equation 7-3 include:

- C = constraint on an element of transmission system[32]
- Y = Year
- b = Bulk System

[31] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[32] If system-wide marginal costs are used, this is not an applicable subscript.

- r = Retail Delivery or Connection Point

$\Delta\mathbf{PeakLoad}_{\mathbf{Y,r}}$ **(ΔMW)** is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"). This input is project specific. A positive value represents a reduction in peak load.

$\mathbf{Loss\%}_{\mathbf{Y,b \to r}}$ **(%)** is the variable loss percent between the bulk system ("b") and the retail delivery point ("r"). Thus, this reflects the sum of the transmission and distribution system loss percent values.

$\mathbf{TransCoincidentFactor}_{\mathbf{C,Y}}$ **(dimensionless)** quantifies a project's contribution to reducing transmission system peak demand relative to its expected maximum demand reduction capability. For example, an expected maximum demand reduction capability of 100 kW with a coincidence factor of 0.8 will reduce the transmission system peak by 80 kW (without considering $DeratingFactor_Y$). This input is project specific.

$\mathbf{DeratingFactor}_{\mathbf{Y}}$ **(dimensionless)** is presented here as a generic factor to de-rate the transmission system coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to peak load reduction on the transmission system. This input is project specific.

$\mathbf{MarginalTransCost}_{\mathbf{C,Y,b}}$ **($/MW-yr)** is the marginal cost of the transmission equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system ("b"). If the available marginal cost of service value is based on a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In some limited circumstances use of the system average marginal cost have been accepted, for example, for evaluation of energy efficiency programs. System average marginal cost of service values are provided in Section 9.

7.1.3.2 General Considerations

In order to find the impact of the measure, project, or portfolio on the transmission system peak load, the "nameplate" capability or load impact must be multiplied by the transmission system coincidence factor and derating factor. Coincidence factors and derating factors would need to be determined by a project-specific engineering study.

Some transmission capacity costs are already embedded in both LBMP and AGCC. Both the AGCC and transmission congestion charges could be decreased in the event that additional transmission assets are built or load is reduced. To the extent that deferred or avoided transmission upgrades are incremental to the value captured in LBMP and AGCC and can be modeled or calculated, these benefits would be reported in this benefit. This value would need to be project-specific based on the specific deferral and/or change to the system topology rather than through generic utility marginal cost of service studies. Using system average marginal costs to estimate avoided transmission and infrastructure need may result in significant over- or under-valuation of the benefits or costs and may result in no savings in utility costs for customers.

The use of project-specific values helps ensure that the calculated impact is applicable to the specific impact of the project both on a temporal and locational basis, adjusting for losses (i.e., locational alignment) and coincidence with the transmission peak (i.e., temporal alignment). In other words, the load reduction ultimately used to value this benefit must be coincident with the load on the relieved equipment. It is important to distinguish between system and local constraints in order to match the impact with the avoided cost. It is assumed that the marginal cost of service is based on the load at the bulk system. If the available marginal cost of service value is based on a different location in the system (e.g., interface between transmission and distribution), then this parameter must first be converted to represent load at the bulk system prior to using in the equation above.

Avoided transmission infrastructure cost benefits are realized only if the project improves load profiles that would otherwise create a need for incremental infrastructure. Benefits are only accrued when a transmission constraint is relieved due to coincident peak load reduction from DER. Under constrained conditions, it is assumed that a peak load reduction impact will produce benefits in the following year as the impact. Once the peak load reduction is less than that necessary to avoid or defer the transmission investment and infrastructure must be built, or the constraint is relieved, this benefit would not be realized from that point forward.

The marginal cost of transmission capacity values provided in Section 9 include both capital and O&M, and cannot be split between the two benefits. Therefore care should be taken to avoid double counting of any O&M values included in this benefit and in the Avoided O&M benefit described in Section 7.2.2.

7.1.4 Avoided Transmission Losses

Avoided Transmission Losses is the benefit that is realized when a project changes the topology of the transmission system and results in a change to the transmission system loss percent. Reductions in end use consumption and demand that result in reduced losses are included in Avoided LBMP and Avoided Generation Capacity benefits as described above in Sections 5.1.2 and 5.1.1. In actuality, both the LBMP and AGCC would adjust to a change in system losses in future years; however, the static forecast used in this methodology does not capture these effects.

7.1.4.1 Benefit Equation, Variables, and Subscripts

Equation 7-4 presents the benefit equation for Avoided Transmission Losses:

EQUATION 7-4. AVOIDED TRANSMISSION LOSSES

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \mathrm{SystemEnergy}_{Z,Y+1,b} * \mathrm{LBMP}_{Z,Y+1,b} * \Delta\mathrm{Loss\%}_{Z,Y+1,b\to i} + \mathrm{SystemDemand}_{Z,Y,b} * \mathrm{AGCC}_{Z,Y,b} * \Delta\mathrm{Loss\%}_{Z,Y,b\to i}$$

Where,

$$\Delta\mathrm{Loss\%}_{Z,Y,b\to i} = \mathrm{Loss\%}_{Z,Y,b\to i,baseline} - \mathrm{Loss\%}_{Z,Y,b\to i,post}$$

The indices[33] of the parameters in Equation 7-4 include:

- Z = NYISO Zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[34])
- Y = Year
- b = Bulk System
- i = Interface of the transmission and distribution systems

$\mathrm{SystemEnergy}_{Z,Y+1,b}$ **(MWh)** is the annual energy forecast by NYISO in the Load & Capacity Report at the bulk system ("b"), which includes transmission and distribution losses. Note that total system energy is used for this input, not the project-specific energy, because this benefit is only included in the BCA when the system topology is changed resulting in a change in the transmission loss percent, which affects all load in the relevant area.

$\mathrm{LBMP}_{Z,Y+1,b}$ **($/MWh)** is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

[33] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[34] NYISO Localities to NYISO Zone Mapping: ROS = A-F, LHV = G-I, NYC = J, LI = K

$\mathbf{SystemDemand_{Z,Y,b}}$ **(MW)** is the system peak demand forecast by NYISO at the bulk system level ("b"), which includes transmission and distribution losses by zone. Note that the system demand is used in this evaluation, not the project-specific demand, because this benefit is only quantified when the system topology is changed resulting in a change in transmission losses percent, which affects all load in the relevant zone.

$\mathbf{AGCC_{Z,Y,b}}$ **($/MW-yr)** represents the annual AGCCs based on forecast of capacity prices for the wholesale market provided by Staff. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level"[35] based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr.

$\mathbf{\Delta LossFactor_{Z,Y,b\rightarrow i}}$ **(Δ%)** is the change in fixed and variable loss percent between the bulk system ("b") and the interface of the transmission and distribution systems ("i") resulting from a project that changes the topology of the transmission system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

$\mathbf{Loss\%_{Z,Y,b\rightarrow i,baseline}}$ **(%)** is the baseline fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses pre-project, which is found in Section 9.

$\mathbf{Loss\%_{Z,Y,b\rightarrow i,post}}$ **(%)** is the post-project fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses post-project.

7.1.4.2 General Considerations

Transmission losses are already embedded in the LBMP. This benefit is incremental to what is included in LBMP and is only quantified when the transmission loss percent is changed (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are based on system-wide energy and demand, not project-specific, because this benefit is only quantified when the losses percentage is changed which

[35] "Transmission level" represents the bulk system level ("b").

affects all customers in the affected area. Transmission losses will not affect downstream distribution losses.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with "Y" and "Y+1" subscripts to indicate the timing of the benefits relative to the impacts.

7.1.5 Avoided Ancillary Services (Spinning Reserves and Frequency Regulation)

Avoided Ancillary Services benefits may accrue to selected DERs that are willing and qualify to provide ancillary services to NYISO. NYISO could purchase ancillary services from these DERs in lieu of conventional generators at a lower cost without sacrificing reliability. This benefit will only be quantified in cases where a measure, project, or portfolio is qualified to, or has the ability and willingness to provide ancillary services to NYISO. This value will be zero for nearly all cases and by exception would a value be included as part of the UCT and RIM.

DER causes a reduction in load but will not directly result in a reduction in NYISO requirements for regulation and reserves since these requirements are not based on existing load levels but instead are based on available generating resource characteristics. Regulation requirements are periodically set by NYISO to maintain frequency, and reserve requirements are set to cover the loss of the largest supply element(s) on the bulk power system.

Some DERs may have the potential to provide a new distribution-level ancillary service such as the voltage support and power quality. However, it is uncertain whether such attributes can be cost-effectively provided by dispersed DERs. The infrastructure costs required to monitor the applicable system conditions (voltage, flicker, etc.) and individual DERs as well as the operations and communications system to communicate with and effectively dispatch those DER attributes are also uncertain. It is premature to include any value in the BCA for such services unless and until the utilities can cost-effectively build the systems to monitor and dispatch DERs to capture net distribution benefits.

7.1.5.1 Benefit Equation, Variables, and Subscripts

The benefits of each of two ancillary services (spinning reserves, and frequency regulation) are described in the equations below. The quantification and inclusion of this benefit is project specific.

Avoided Frequency Regulation

Equation 7-5 presents the benefit equation for Avoided Frequency Regulation:

EQUATION 7-5. AVOIDED FREQUENCY REGULATION

$$\text{Benefit}_Y = \Delta\text{Capacity}_Y * n * (\text{CapPrice}_Y + \text{MovePrice}_Y * \text{RMM}_Y)$$

The indices of the parameters in equation 7-5 include:

- Y = Year

$\Delta\text{Capacity}_Y$ (ΔMW) is the amount of annual average frequency regulation capacity when provided to NYISO by the project. The amount is difficult to forecast.

n (hr) is the number of hours in a year that the resource is expected to provide the service.

CapPrice_Y ($/MW·hr) is the average hourly frequency regulation capacity price. The default value is the two-year historical average for day-ahead regulation capacity prices from NYISO.

MovePrice_Y ($/ΔMW): is the average hourly frequency regulation movement price. The default value is the two-year historical average for real-time dispatch of regulation movement prices from NYISO.

RMM_Y (ΔMW/MW·hr): is the Regulation Movement Multiplier (RMM) used for regulation bids and accounts for the ratio between movement and capacity. It is assumed to be 13 ΔMW/MW-hr.

Spinning Reserves

Equation 7-6 presents the benefit equation for Spinning Reserves:

EQUATION 7.6 SPINNING RESERVES

$$\text{Benefit}_Y = \Delta\text{Capacity}_Y * n * \text{CapPrice}_Y$$

The indices of the parameters in equation 7-6 include:

- Y = Year

$\Delta\text{Capacity}_Y$ (ΔMW)is the change in the amount of annual average spinning reserve capacity when provided to the NYISO by the project. The amount is difficult to forecast.

n (hr): is the number of hours in a year that the resource is expected to provide the service.

CapPrice_Y ($/MW·hr) is the average hourly spinning reserve capacity price. Default value uses the two-year historical average spinning reserve pricing by region.

7.1.5.2 General Considerations

There are no reductions in annual average frequency regulation, and spinning reserve, because those are set by the NYISO independent of load levels and DER penetration.

NYISO in late 2015 changed the number of regions for Ancillary Services from two to three and two-year historical data is not available for all three regions. Thus, assume that EAST and SENY are equal to the historical data for EAST. The corresponding NYISO zones for EAST are F – K, and the corresponding zones for WEST are A – E.

The average hourly prices for frequency regulation capacity, frequency regulation movement, and spinning reserve capacity can be calculated from historical pricing data posted by NYISO. The recommended basis is a historical average of interval pricing over the prior two-year period. To avoid the complication of the change in regions, the two-year historical average is based on November 1, 2013 through October 31, 2015.

The NYISO Ancillary Services Manual suggests that the day-ahead market is the predominant market for regulation capacity and spinning reserves; regulation movement is only available in real-time.

The RMM is fixed by NYISO at a value of 13 ΔMW/MW per hour. While NYISO does not publish historical interval volume data to calculate actual movement, this value can be considered a reasonable proxy for actual movement.

7.1.6 Wholesale Market Price Impact

Wholesale Market Price Impact includes the benefit from reduced wholesale market prices on both energy (i.e., LBMP) and capacity (i.e., AGCC) due to a measure, project, or portfolio. LBMP impacts will be provided by Staff and are determined using the first year of the most recent CARIS database to calculate the static impact on wholesale LBMP of a 1% change in the level of load that must be met.[36] LBMP impact will be calculated for each NYISO zone. AGCC price impacts are characterized using Staff's ICAP Spreadsheet Model.

7.1.6.1 Benefit Equation, Variables, and Subscripts

Equation 7-7 presents the benefit equation for Wholesale Market Price Impact:

[36] BCA Order, Appendix C, pg. 8.

EQUATION 7-7 WHOLESALE MARKET PRICE IMPACT

$$\text{Benefit}_{Y+1} = \sum_{Z} (1 - \text{Hedging\%}) * (\Delta\text{LBMPImpact}_{Z,Y+1,b} * \text{WholesaleEnergy}_{Z,Y+1,b} + \Delta\text{AGCC}_{Z,Y,b} * \text{ProjectedAvailableCapacity}_{Z,Y,b})$$

The indices of summation for Equation 7-7 include:

- Z = NYISO Zone (A → K[37])
- Y = Year
- b = Bulk System

Hedging% (%) is the fraction of energy or capacity hedged via fixed price or multi-year agreements or other mechanisms. Price hedging via long term purchase contracts should be considered when assessing wholesale market price impacts. The JU have generally assumed that the percent of purchases hedged is 50% and equal for both energy and capacity.

$\Delta\text{LBMPImpact}_{Z,Y+1,b}$ (Δ$/MWh) is the change in average annual LBMP at the bulk system ("b") before and after the project(s); requires wholesale market modeling to determine impact. This will be provided by DPS Staff.

$\text{WholesaleEnergy}_{Z,Y,b}$ (MWh) is the total annual wholesale market energy purchased by zone at the bulk system level ("b"). This must represent the energy at the LBMP.

$\Delta\text{AGCC}_{Z,Y,b}$ (Δ$/MW-yr) is the change in AGCC price by ICAP zone calculated from Staff's ICAP Spreadsheet Model before and after the project is implemented. This value is determined based on the difference in zonal prices in Staff's ICAP Spreadsheet Model, "AGCC Annual" tab, based on a change in the supply or demand forecast (i.e., "Supply" tab and "Demand" tab, respectively) due to the project.[38] The price impacts are based on the size and location of the project. A positive value represents a reduction in price.

$\text{ProjectedAvailableCapacity}_{Z,Y,b}$ (MW) is the projected available supply capacity by ICAP zone at the bulk system level ("b") based on Staff's ICAP Spreadsheet Model, "Supply" tab, which is the baseline before the project is implemented.

[37] NYISO Localities to NYISO Zone Mapping: ROS = A-F, LHV = G-I, NYC = J, LI = K
[38] As in the AGCC benefit equation, System Coincidence Factors and Derating Factors adjust the maximum load reduction of the project.

7.1.6.2 General Considerations

Wholesale market price impacts or demand reduction induced price effects are project specific based on the size and shape of the demand reduction. LBMP market price impacts will be provided by Staff and will be determined using the first year of the most recent CARIS database to calculate the static impact on LBMP of a 1% change in the level of load that must be met in the utility area where the DER is located. These impacts must be considered in the benefit calculation once available. The capacity market price impacts can be calculated using Staff's ICAP Spreadsheet Model. The resultant price effects are not included in SCT, but would be included in RIM and UCT as a sensitivity.

It is assumed that Wholesale Market Price Impacts do not result in benefits for more than one year, as these markets will respond quickly to the reduced demand, quickly reducing the benefit.[39]. It is also assumed that the capacity portion of Wholesale Market Price Impacts will produce benefits in the year following the impact, and the energy portion of Wholesale Market Price Impacts will produce benefits in the same year as the impact.

7.2 Distribution System Benefits

7.2.1 Avoided Distribution Capacity Infrastructure

Avoided Distribution Capacity Infrastructure benefit results from location-specific distribution load reductions that are valued at the marginal cost of distribution system infrastructure that is avoided or deferred by a DER project or program. The load reduction impact must be coincident with the distribution equipment peak or otherwise defer or avoid the need for incremental distribution infrastructure based on the characteristics of the specific load and the design criteria of the specific equipment that serves it.

7.2.1.1 Benefit Equation, Variables, and Subscripts

Equation 7-8 presents the benefit equation for Avoided Distribution Capacity Infrastructure:

EQUATION 7-8 AVOIDED DISTRIBUTION CAPACITY INFRASTRUCTURE

$$\text{Benefit}_{\text{Y}} = \sum_{\text{V}} \sum_{\text{C}} \frac{\Delta\text{PeakLoad}_{\text{Y,r}}}{\text{Loss\%}_{\text{Y,b}\rightarrow\text{r}}} * \text{DistCoincidentFactor}_{\text{C,V,Y}} * \text{DeratingFactor}_{\text{Y}} * \text{MarginalDistCost}_{\text{C,V,Y,b}}$$

The indices of summation for Equation 7-8 include:

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[39] The one year assumption is based on an overview of price suppression provided in the New England Regional Avoided Cost Study 2015

- C =Constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of the distribution system[40]
- V = Voltage level (e.g., primary, and secondary)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

ΔPeakLoad$_{C,V}$ (MW) is the nameplate demand reduction of the project at the retail delivery or connection point ("r"). This input is project specific. A positive value represents a reduction in peak load.

$\mathrm{Loss\%}_{Y,b\rightarrow r}$ (%) is the variable loss percent between the bulk system ("b") and the retail delivery point ("r"). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Section 9. This parameter to used to adjust the $\Delta\mathrm{PeakLoad}_{Y,r}$ parameter to the bulk system level.

$\mathrm{DistCoincidentFactor}_{C,V,Y}$ (dimensionless) captures the contribution to the distribution element's peak relative to the project's nameplate demand reduction. For example, a nameplate demand reduction of 100 kW on the distribution feeder with a coincidence factor of 0.8 would contribute an 80 kW reduction to peak load on an element of the distribution system. This input is project specific.

$\mathrm{DeratingFactor}_{Y}$ (dimensionless) is presented here as a generic factor to de-rate the distribution coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its peak load reduction contribution on an element of the distribution system. This input is project specific.

$\mathrm{MarginalDistCost}_{C,V,Y,b}$ ($/MW-yr) is the marginal cost of the distribution equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system ("b"). If the available marginal cost of service value is based on a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In some limited circumstances use of the system average marginal cost have been

[40] In limited cases where use of system-wide marginal cost values is required, this subscript is not applicable.

accepted, for example, for evaluation of energy efficiency programs. System average marginal cost of service values are provided in Section 9.

7.2.1.2 General Considerations

Project- and location- specific avoided distribution costs and deferral values should be used when and wherever possible. Using system average marginal costs to estimate avoided transmission and distribution infrastructure need may result in significant over- or under-valuation of the benefits or costs, and may result in no savings in utility costs for customers. Coincidence and derating factors would be determined by a project-specific engineering study.

Avoided distribution infrastructure benefits for a specific location are realized only if a DER project or portfolio of DER projects meets the engineering requirements for functional equivalence (i.e., DER reliably reduces coincident load to a level that allows the deferral or avoidance of the distribution project. The DSIP identifies specific areas where a distribution upgrade need exists and where DERs could potentially provide this benefit.

Use of system average avoided cost assumptions may be required in some situations, such as system-wide programs or tariffs. These values are provided in Section 9.

The timing of benefits realized from peak load reductions are project and/ or program specific. It is assumed that a peak load reduction impact will produce benefits in the year of the impact. Once the peak load reduction is no longer enough to avoid or defer investment and infrastructure must be built, the constraint is relieved and benefits should not be realized from that point forward.

The marginal cost of distribution capacity values provided in Section 9 include both capital and O&M, and cannot be split between the two benefits. Therefore, whenever these system average values are used, care should be taken to avoid double counting of any O&M values included in this benefit and in the Avoided O&M benefit described in Section 7.

7.2.2 Avoided O&M

Avoided O&M includes any benefits incremental to the value captured in the Avoided Distribution Capacity Infrastructure benefit (Section 7.2.1). As discussed above, marginal cost studies include O&M and that O&M is not separately included in this benefit. Therefore, this benefit includes reduced expenses not tied to avoided or deferred distribution system investment from DER. This benefit may capture O&M savings from investments to improve customer service that reduces phone calls to the call center or O&M savings from migrating toward advanced meter functionality reducing meter reading costs. At this time, for most DER projects this benefit will be zero. For example, DER may reduce equipment loading, which reduces failure rates, but somewhat higher equipment loading may have led to the installation of new equipment with lower O&M costs. Further analysis is required to understand how DER would impact O&M.

7.2.2.1 Benefit Equation, Variables, and Subscripts

Equation 7-9 presents the benefit equation for Avoided O&M Costs:

EQUATION 7-9. AVOIDED O&M

$$\text{Benefit}_{\text{Y}} = \sum_{\text{AT}} \Delta\text{Expenses}_{\text{AT,Y}}$$

The indices of summation for Equation 7-9 include:

- AT = activity type (e.g., line crews to replace equipment, engineering review of DER interconnection applications, responding to calls received at call centers)
- Y = Year

$\Delta\text{Expenses}_{\text{AT,Y}}$ (Δ$): Change in O&M expenses due to a project, including an appropriate allocation of administrative and common costs. These costs would increase by inflation, where appropriate.

7.2.2.2 General Considerations

Distribution O&M benefits from DERs may be limited to instances where DERs can avoid or defer new distribution equipment, which is already captured in the Avoided Distribution Capacity Infrastructure benefit (Section 7.2.1), where the O&M costs are embedded in the marginal cost of service values. DER interconnections could increase O&M costs, while lower equipment failure rates could decrease these costs. In general, these impacts are difficult to quantify for DER investments and may be zero for most cases.

Avoided O&M benefits would be quantifiable for some non-DER investments, such as utility investments in DSP capabilities. For example, a utility investment in advanced metering functionality may avoid truck rolls and other costs by collecting meter data remotely. Labor and crew rates can be sourced using the utility's activity-based costing system or work management system, if that information is available.

7.2.3 Distribution Losses

Avoided Distribution Losses are the incremental benefit that is realized when a project changes distribution system losses, resulting in changes to both annual energy use and peak demand. Distribution losses are already accounted for in the LBMP and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of LBMPs and

AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%).

7.2.3.1 Benefit Equation, Variables, and Subscripts

Equation 7-10 presents the benefit equation for Avoided Distribution Losses:

EQUATION 7-10 AVOIDED DISTRIBUTION LOSSES

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \mathrm{SystemEnergy}_{Z,Y+1,b} * \mathrm{LBMP}_{Z,Y+1,b} * \Delta\mathrm{Loss\%}_{Z,Y+1,i\rightarrow r} + \mathrm{SystemDemand}_{Z,Y,b} * \mathrm{AGCC}_{Z,Y,b} * \Delta\mathrm{Loss\%}_{Z,Y,i\rightarrow r}$$

Where,

$$\Delta\mathrm{Loss\%}_{Z,Y,i\rightarrow r} = \mathrm{Loss\%}_{Z,Y,i\rightarrow r,\mathrm{baseline}} - \mathrm{Loss\%}_{Z,Y,i\rightarrow r,\mathrm{post}}$$

The indices[41] of the parameters in Equation 7-10 include:

- Z = NYISO Zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[42])
- Y = Year
- i = Interface Between Transmission and Distribution Systems
- b = Bulk System
- r = Retail Delivery or Connection Point

$\mathbf{SystemEnergy_{Z,Y,b}}$ **(MWh)** is the system energy purchased in the relevant area of the distribution system (i.e., the portion of the system where losses were impacted by the project) at the retail location by zone. Note that the system energy is used here, not the project-specific energy, because this benefit is only quantified when the distribution loss percent value is changed, which affects all load in the relevant part of the distribution system.

$\mathbf{LBMP_{Z,Y,b}}$ **($/MWh)** is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system l.evel ("b"). To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS

[41] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[42] NYISO Localities to NYISO Zone Mapping: ROS = A-F, LHV = G-I, NYC = J, LI = K.

planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

$\mathbf{SystemDemand_{Z,Y,b}}$ **(MW)** is the system peak demand for the portion of the retail location on the distribution system(s) (i.e., the portion of the system where losses are impacted by the project) for the relevant NYISO capacity zone. This parameter is grossed up to the bulk system level (i.e., location of the AGCC) based on the $\mathrm{Loss\%_{Z,b\rightarrow r}}$ parameter. Note that the system demand is used in this evaluation, not the project-specific demand, because this benefit is only quantified when the system topology is changed resulting in a change in distribution loss percent, which affects all load in the relevant part of the distribution system.

$\mathbf{AGCC_{Z,Y,b}}$ **($/MW-yr)** represents the annual AGCCs at the bulk system level ("b") based on forecast of capacity prices for the wholesale market provided by Staff. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level" based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr.

$\mathbf{\Delta LossFactor_{Z,Y,i\rightarrow r}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the transmission and distribution systems ("i") and the retail delivery point ("r") resulting from a project that changes the topology of the distribution system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

$\mathbf{Loss\%_{Z,Y,i\rightarrow r,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in Section 9.

$\mathbf{Loss\%_{Z,Y,i\rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r").

7.2.3.2 General Considerations

Distribution losses are already accounted for in the LBMP and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of LBMPs and AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are grossed up from retail impacts to transmission system impacts based on losses in the equations above. Impacts are based on system-wide energy and demand, not project-specific, because this benefit is only quantified when the loss percentage is changed which affects all load in the affected area. Note that distribution losses also affect upstream transmission losses. Because losses data is usually only available on an annual average basis, the energy and demand impacts should be on an annual average basis as well.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with “Y” and “Y+1” subscripts to indicate the time delay of benefits relative to the impacts.

7.3 Reliability/Resiliency Benefits

7.3.1 Net Avoided Restoration Costs

Avoided Restoration Costs accounts for avoided costs of restoring power during outages. For most DER investments, this benefit will not be quantified, as utilities will have to fix the cause of the outage regardless of whether the DER allows the customer operate independently of the grid. For some non-DER investments such as automatic feeder switching, distribution automation and enhanced equipment monitoring, the utility may save time and other expenses dispatching restoration crews as a result of having improved visibility into the type and nature of the fault. Storm hardening and other resiliency investments can reduce the number of outage events, resulting in reduced restoration crew hours:

7.3.1.1 Benefit Equation, Variables, and Subscripts

Equation 7-11 presents the benefit equation for Net Avoided Restoration Costs:

EQUATION7-11 NET AVOIDED RESTORATION COSTS

$$\mathrm{Benefit_Y} = \Delta\mathrm{CrewTime_Y} * \mathrm{CrewCost_Y} + \Delta\mathrm{Expenses_Y}$$

$$\textit{Where,}$$

$$\Delta\mathrm{CrewTime_Y} = \#\mathrm{Interruptions_{base,Y}} * (\mathrm{CAIDI_{base,Y}} - \mathrm{CAIDI_{post,Y}} * (1 - \Delta\%\mathrm{SAIFI_Y}))$$

$$\Delta\%\mathrm{SAIFI_Y} = \frac{\mathrm{SAIFI_{base,Y}} - \mathrm{SAIFI_{post,Y}}}{\mathrm{SAIFI_{base,Y}}}$$

There are no indices of the parameters besides “base”, “post”, and Year in Equation 7-11 because we assume an average restoration crew cost that does not change based on the type of outage.

$\Delta\mathbf{CrewTime_Y}$ **(Δhours/yr)** is the change in crew time to restore outages based on an impact on frequency and duration of outages.

$\mathbf{CrewCost_Y}$ **($/hr)** is the average hourly outage restoration crew cost for activities associated with the project under consideration as provided in Section 9.

$\Delta\mathbf{Expenses_Y}$ **($\Delta$$)** are the expenses (e.g. equipment replacement) associated with outage restoration.

$\#\mathbf{Interruptions_{base,Y}}$ **(int/yr)** are the number of sustained interruptions per year, excluding major storms, in the baseline scenario. Baseline system total values are provided in Section 9.

$\mathbf{CAIDI_{base,Y}}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index; it represents the average time to restore service, excluding major storms. Note that this parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects. Baseline system total values are provided in Section 9.

$\mathbf{CAIDI_{post,Y}}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index; represents the average time to restore service, excluding major storms. This parameter would require an engineering study or model to quantify. Note that this parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\Delta\%\mathbf{SAIFI_Y}$ **(Δ%)**: percent change in System Average Interruption Frequency Index; represents the percent change in the average number of times that a customer experiences an outage per year.

$\mathbf{SAIFI_{base,Y}}$ **(outages/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index; represents the average number of times that a customer experiences an outage per year in the baseline scenario. Note that this parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{SAIFI_{post,Y}}$ **(outages/cust/yr)** is the post-project System Average Interruption Frequency Index; represents the average number of times that a customer experiences an outage per year in the post-project scenario. Note that this parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

7.3.1.2 General Considerations

The impact on SAIFI or CAIDI is due to the implementation of the project relative to a baseline, not based on outside factors such as weather. The changes to these parameters should consider the appropriate context of the project, for example, impact to one feeder or impact to a portion of the distribution system. The baseline values should match the portion of the system impacted. In addition, one should consider the types of outage event and how the project may or may not address each type of outage event to inform the magnitude of impact.

In addition to being project-specific, calculation of avoided restoration costs is dependent on projection of the impact of specific investments affect the facilitation of actual system restoration and the respective costs. It is unrealistic to expect that DER investments will limit or replace the need to repair field damage to the system, and as such, system restoration benefits attributable to DER type investments are likely to be none. However, as measurement capabilities and DER experience evolve, utilities may be able to develop tools to evaluate reliability benefits of DER vs. traditional utility equipment and that could be used to calculate any feeder and system level reliability benefits that may be provided by specific DER technologies.. Presently, in the absence of data on reliability benefits provided by specific DER investments, application of this benefit is applicable only to investments in DSP capabilities.

7.3.2 Net Avoided Outage Costs

Avoided Outage Costs accounts for customer outage costs due to a reduction in frequency and duration of outages, then multiplying that expected change by an estimated outage cost. The quantification of this benefit is highly dependent on the type and size of affected customers.

7.3.2.1 Benefit Equation, Variables, and Subscripts

Equation 7-12 presents the benefit equation for Net Avoided Outage Costs:

EQUATION 7-12. NET AVOIDED OUTAGE COSTS

$$\text{Benefit}_{\text{Y}} = \sum_{\text{C}} \text{ValueOfService}_{\text{C,Y,r}} * \text{AverageDemand}_{\text{C,Y,r}} * \Delta\text{SAIDI}_{\text{Y}}$$

Where,

$$\Delta\text{SAIDI}_{\text{Y}} = \text{SAIFI}_{\text{base,Y}} * \text{CAIDI}_{\text{base,Y}} - \text{SAIFI}_{\text{post,Y}} * \text{CAIDI}_{\text{post,Y}}$$

The indices of summation for Equation 7-12 include:

- C = Customer class (e.g., residential, small C&I, large C&I) – BCA should use customer-specific values if available.
- Y = Year

- r = Retail Delivery or Connection Point

$\mathrm{ValueOfService}_{C,Y,r}$ **($/kWh)** is the value of electricity service to customers, by customer class, in dollars per unserved kWh at the retail delivery point. The value(s) should be determined based on the customers' willingness to pay for reliability. If location-, customer class- or customer-specific values are not available, these values should default to the retail rate of electricity by customer class.

$\mathrm{AvgDemand}_{C,Y,r}$ **(kW)** is the average demand in kW at the retail delivery or connection point ("r") that would otherwise be interrupted during outages but can remain electrified due to DER equipment and/or utility infrastructure. This would need to be identified by customer class, or by customer, if available. If the timing of outages cannot be predicted, this parameter can be calculated by dividing the annual energy consumption by 8,760 hours per year.

$\Delta\mathrm{SAIDI}_{Y}$ **(∆int/cust/yr):** is the change in System Average Interruption Duration Index due to the project. The impact on SAIDI can be determined based on the impact on CAIDI and SAIFI.[43] Baseline system average reliability metrics can be found in Section 9. A positive value represents a reduction in SAIDI.

$\mathrm{SAIFI}_{post,Y}$ **(outages/cust/yr)** is the post-project System Average Interruption Frequency Index; represents the average number of times that a customer experiences an outage per year in the post-project case.

$\mathrm{CAIDI}_{post,Y}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index; represents the impact of a project on the average time to restore service in the post-project case.

$\mathrm{SAIFI}_{base,Y}$ **(outages/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average and excludes major storms, and is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathrm{CAIDI}_{base,Y}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index. It represents the impact of a project on the average time to restore service, excluding major storms. The baseline system-wide is a five-year average and excludes major storms, and is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

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[43] SAIDI = SAIFI * CAIDI

7.3.2.2 General Considerations

The value of the avoided outage cost benefit is to be customer-specific, customer class should match or be consolidated properly between the utility and the study area to ensure that the value of reliability matches, what the customer would be willing to pay.

For this version of the BCA Handbook, the outage cost can be estimated by assuming the customer would be willing to pay the same retail rate they pay for electricity, to avoid an outage. The full retail rate value can be found in the utility's latest tariff by customer class.

At this time, the Standard Interconnection Requirements do not allow for islanding, and therefore limit this configuration to a DER that meets the needs of a customer during an outage. Therefore, there are limited instances where DER allows the customer to supply local load in a blackout and resulting benefits would then be limited to that load picked up by DER.

7.4 External Benefits

7.4.1 Net Avoided CO_2

Net Avoided CO_2 accounts for avoided CO_2 due to a reduction in system load levels[44] or the increase of CO_2 from onsite generation. The CARIS forecast of LBMP contains a cost of carbon based on the Regional Greenhouse Gas Initiative (RGGI). Staff will provide a $/MWh adder to account for the net marginal damage cost of carbon that is not already captured in the LBMP. This adder is based on the United States Environmental Protection Agency damage cost estimates for a 3% real discount rate. Staff then provides a $/MWh for the full marginal damage cost and the net marginal damage costs of CO_2. The net marginal damage costs is the full marginal damage cost less the cost of carbon embedded in the LBMP.

7.4.1.1 Benefit Equation, Variables, and Subscripts

Equation 7-13 presents the benefit equation for Net Avoided CO_2:

EQUATION 7-13 NET AVOIDED CO_2

$$\text{Benefit}_Y = \text{CO2Cost}\Delta\text{LBMP}_Y - \text{CO2Cost}\Delta\text{OnsiteEmissions}_Y$$

Where,

[44] The Avoided CO_2 benefit considers the change in energy as a result of the project by including the change in energy identified in the Avoided LBMP, Avoided Transmission Losses, and Avoided Distribution Losses benefits.

$$\mathrm{CO2Cost\Delta LBMP_{Y}} = \left(\frac{\Delta \mathrm{Energy}_{\mathrm{Y,r}}}{1 - \mathrm{Loss\%}_{\mathrm{Y,b \to r}}} + \Delta \mathrm{Energy}_{\mathrm{TransLosses,Y}} + \Delta \mathrm{Energy}_{\mathrm{DistLosses,Y}}\right) * \mathrm{NetMarginalDamageCost}_{\mathrm{Y}}$$

$$\Delta \mathrm{Energy}_{\mathrm{TransLosses,Y}} = \mathrm{SystemEnergy}_{\mathrm{Y,b}} * \Delta \mathrm{Loss\%}_{\mathrm{Y,b \to i}}$$

$$\Delta \mathrm{Energy}_{\mathrm{DistLosses,Y}} = \mathrm{SystemEnergy}_{\mathrm{Y,b}} * \Delta \mathrm{Loss\%}_{\mathrm{Y,i \to r}}$$

$$\Delta \mathrm{Loss\%}_{\mathrm{Z,Y,b \to i}} = \mathrm{Loss\%}_{\mathrm{Z,Y,b \to i,baseline}} - \mathrm{Loss\%}_{\mathrm{Z,Y,b \to i,post}}$$

$$\Delta \mathrm{Loss\%}_{\mathrm{Z,Y,i \to r}} = \mathrm{Loss\%}_{\mathrm{Z,Y,i \to r,baseline}} - \mathrm{Loss\%}_{\mathrm{Z,Y,i \to r,post}}$$

$$\mathrm{CO2Cost\Delta OnsiteEmissions_{Y}} = \Delta \mathrm{OnsiteEnergy}_{\mathrm{Y}} * \mathrm{CO2Intensity}_{\mathrm{Y}} * \mathrm{SocialCostCO2}_{\mathrm{Y}}$$

The indices of the parameters in Equation 7-13 include:

- Y = Year
- b = Bulk System
- i = Interface of the Transmission and Distribution Systems
- r = Retail Delivery or Connection Point

$\mathbf{CO2Cost\Delta LBMP_{Y}}$ **($)** is the cost of CO_2 due to a change in wholesale energy purchased. A portion of the full CO_2 cost is already captured in the Avoided LBMP benefit. The incremental value of CO_2 is captured in this benefit, and is valued at the net marginal cost of CO_2, as described below.

$\mathbf{CO2Cost\Delta OnsiteEmissions_{Y}}$ **($)** is the cost of CO_2 due to DER that is not emission-free. The cost of carbon for customer-sited emissions is based upon the gross marginal cost of CO_2, as described below.

$\mathbf{\Delta Energy_{Y,r}}$ **(ΔMWh)** is the change in energy purchased at the retail delivery or connection point ("r") as a result of the project. This parameter considers the energy impact at the project location, which is then grossed up to the bulk system level based on the $Loss\%_{b \to r}$ parameter. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Y,b \to r}}$ **(%)** is the variable loss percent from the bulk system level ("b") to the retail delivery or connection point ("r"). These values can be found in Section 9.

$\mathbf{\Delta Energy_{TransLosses,Y}}$ **(ΔMWh)** represents the change in electricity lost on the transmission system due to the Avoided Transmission Losses benefit. Refer to Section 5.2 for more details.

In most cases, unless the transmission system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in transmission system losses.

$\mathbf{\Delta Energy_{DistLosses,Y}}$ **(ΔMWh)** represents the change in energy lost on the distribution system due to the Avoided Distribution Losses benefit. Refer to Section 7.2.3 for more details. In most cases, unless the distribution system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in distribution system losses.

$\mathbf{NetMarginalDamageCost_Y}$ **($/MWh)** is the "adder" Staff will provide to account for the full marginal damage cost of carbon that is not already captured in the forecast of LBMP from CARIS. The LBMP forecast from CARIS includes the cost of carbon based on the RGGI, but does include the SCC from the U.S. EPA.

$\mathbf{\Delta Loss\%_{Z,Y,b\rightarrow i}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the bulk system ("b") and the interface between the transmission and distribution systems ("i"). This represents the change in the transmission system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathbf{Loss\%_{Z,Y,b\rightarrow i,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface between the bulk system ("b") and the interface between the transmission and distribution systems ("i"). Thus, this reflects the transmission loss percent pre-project, which is found in Table 9-2.

$\mathbf{Loss\%_{Z,Y,b\rightarrow i,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface between the bulk system ("b") and the interface between the transmission and distribution systems ("i"). Thus, this reflects the transmission loss percent post-project, which is found in Section 9.

$\mathbf{\Delta Loss\%_{Z,Y,i\rightarrow r}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the transmission and distribution systems ("i") and the retail delivery point ("r") resulting from a project that changes the topology of the distribution system. This represents the change in the distribution system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathbf{Loss\%_{Z,Y,i\rightarrow r,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in Section 9.

$\mathbf{Loss\%_{Z,Y,i\rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent post-project, which is found in Section 9.

$\Delta\mathbf{OnsiteEnergy_Y}$ **(ΔMWh)** is the energy produced by customer-sited carbon-emitting generation.

$\mathbf{CO2Intensity_Y}$ **(metric ton of CO_2 / MWh)** is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation. Note that there is a difference between metric tons and short tons[45].

$\mathbf{SocialCostCO2_Y}$ **(\$ / metric ton of CO_2)** is an estimate of the total monetized damages to society associated with an incremental increase in carbon dioxide emissions. Annual values are provided by EPA, and are also located in Table A of Attachment B of the BCA Order. Per the BCA Order, the values associated with a 3% real discount rate shall be used. Note that Table A provides values in 2011 dollars; these values must be converted to nominal values prior to using the equation above.

7.4.1.2 General Considerations

The equation above represents two sources of emissions based on: (1) a change in LBMP purchases, which is valued at the \$/MWh adder (i.e., $NetMarginalDamageCost_Y$ parameter above) to be provided by Staff, and (2) customer-sited carbon emissions from onsite generation (e.g., such as combined heat and power [CHP]), which is valued at the social cost of carbon from EPA.

The energy impact is project-specific and should be linked to the impacts determined in the Avoided LBMP benefit. The LBMP impacts due to the Avoided Transmission Losses and Avoided Distribution Losses benefits also need to be account for when determining the total change in LBMP due to a project. It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

The methodology outlined in this section to value Avoided CO_2 may change. The BCA Order indicates "utilities shall rely on the costs to comply with New York's Clean Energy Standard once those costs are known."[46]

7.4.2 Net Avoided SO_2 and NO_x

Net Avoided SO_2 and NO_x includes incremental value of avoided or added emissions. The LBMP already includes the cost of pollutants (i.e., SO_2 and NO_x) as an "internalized" cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs.

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[45] 1 metric ton = 1.10231 short tons
[46] BCA Order, Appendix C, 16.

7.4.2.1 Benefit Equation, Variables, and Subscripts

Equation 7-14 presents the benefit equation for Net Avoided SO_2 and NO_x:

EQUATION 7-14 NET AVOIDED SO_2 AND NO_X

$$\mathrm{Benefit}_{Y} = \sum_{p} \mathrm{OnsiteEmissionsFlag}_{Y} * \mathrm{OnsiteEnergy}_{Y,r} * \mathrm{PollutantIntensity}_{p,Y} * \mathrm{SocialCostPollutant}_{p,Y}$$

The indices of summation for Equation 7-14 include:

- P = Pollutant (SO2, NOx)
- Y = Year
- r = Retail Delivery or Connection Point

$\mathbf{OnsiteEmissionsFlag_{Y}}$ is a binary (i.e., 0 or 1) parameter, where a value of 1 indicates that customer-sited pollutant-emitting generation <25 MW is implemented as a result of the project.

$\mathbf{\Delta OnsiteEnergy_{Y,r}}$ **(ΔMWh)** is the energy produced by customer-sited pollutant-emitting generation.

$\mathrm{PollutantIntensity}_{p,Y}$ **(ton/MWh)** is average pollutant emissions rate of customer-sited pollutant-emitting generation energy. This is a project-specific input.

$\mathrm{SocialCostPollutant}_{p,Y}$ **($/ton)** is an estimate of the monetized damages to society associated with an incremental increase in pollutant emissions in a given year. The allowance prices are provided in CARIS Phase 2.

7.4.2.2 General Considerations

LMBPs already include the cost of pollutants (i.e., SO_2 and NO_x) as an “internalized” cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs. This would be a benefit to the extent that the DER emits less than NYISO generation, and a negative benefit for the DER if it has a higher emissions rate than NYSO generation or emissions –free DER.

Two values are provided in CARIS for NO_x costs: “Annual NO_x” and “Ozone NO_x.” Annual NO_x prices are used October through May; Ozone NO_x prices May through September. The breakdown of energy in these two time periods must be accounted for and applied to the appropriate NO_x cost.

7.4.3 Avoided Water Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

7.4.4 Avoided Land Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

7.4.5 Net Non-Energy Benefits Related to Utility or Grid Operations

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively or if can be estimated quantitatively. It is necessary to identify which cost-effectiveness test should include the specific benefit or cost as it may apply to the SCT, UCT and/or RIM.

7.5 Costs Analysis

7.5.1 Program Administration Costs

Program Administration Costs includes the cost to administer and measure the effect of required program administration performed and funded by utilities or other parties. This may include the cost of incentives, measurement and verification, and other program administration costs to start, and maintain a specific program. The reduced taxes and rebates to support certain investments increase non-participant costs.

7.5.1.1 Benefit Equation, Variables, and Subscripts

Equation 7-15 presents the cost equation for Program Administration Costs:

EQUATION7-15 PROGRAM ADMINISTRATION COSTS

$$\mathrm{Cost}_{\mathrm{Y}} = \sum_{\mathrm{M}} \Delta \mathrm{ProgramAdminCost}_{\mathrm{M,Y}}$$

The indices of summation for Equation 7-15 include:

- M = Measure
- Y = Year

$\Delta \text{ProgramAdminCost}_{M,Y}$ is the change in Program Administration Costs, which may include one-time or annual incentives such as rebates, program administration costs, measurement and verification, state incentives, and other costs. These costs would increase by inflation, where appropriate.

7.5.1.2 General Considerations

Program Administration Costs are program- and project-specific, therefore without a better understanding of the details it is not possible to estimate in advance the Project Administration Cost. Program-specific details that are necessary to calculate the cost impact can include, but are not limited to, the scale of the activity, the types of participating technologies, and locational details. Sub-categories that could fall under Program Administration Costs include, but are not limited to, programmatic measurement & verification costs, utility-specific rebates and/or incentives, and costs of market interventions (e.g., state and federal incentives).

7.5.2 Added Ancillary Service Costs

Added Ancillary Service Costs occur when DER causes additional ancillary service cost on the system. These costs shall be considered and monetized in a similar manner to the method described in the Avoided Ancillary Services benefits section above.

7.5.3 Incremental Transmission & Distribution and DSP Costs

Additional incremental T&D Costs are caused by projects that contribute to the utility's need to build additional infrastructure.

Additional infrastructure costs caused shall be considered and monetized in a similar manner to the method described in Section 7.1.3 Avoided Transmission Capacity Infrastructure and Related O&M. The potential for incremental T&D costs depends on the interconnection location, type of DER, and penetration of other DER in the area. These factors make estimating a value of incremental T&D costs in advance without project-specific information difficult..

Depending on the nature of a specific DER project the incremental costs could be borne by the interconnecting facility or shared among all ratepayers. For instance, a utility may need to make further investment in their T&D infrastructure, such as expanding system capacity, implementing more sophisticated control functionalities, or enhancing protection to ensure seamless grid integration of new DER assets.

In some situations enhanced capabilities of a DSP would be required. These incremental costs would be identified and included within this cost.

In some situations enhanced capabilities of a DSP would be required. These incremental costs would be identified and included within this cost.

7.5.4 Participant DER Cost

Participant DER Cost includes the equipment and participation costs assumed by DER providers which need to be considered when evaluating the societal costs of a project or program. These costs are the full cost of the DER as program rebates, and incentives are included as part of Program Administration Costs.

As the Commission noted in the February 2015 Track 1 Order, the approach employed to obtain DER will evolve over time:

> "*The modernization of New York's electric system will involve a variety of products and services that will be developed and transacted through market initiatives Products, rules, and entrants will develop in the market over time, and markets will value the attributes and capabilities of all types of technologies. As DSP capabilities evolve, procurement of DER attributes will develop as well, from a near-term approach based on RFPs and load modifying tariffs, towards a potentially more sophisticated auction approach*."[47]

Thus, the acquisition of most DER in the near term will be through competitive solicitations rather than the establishment of tariffs. The BCA Order requires a fact specific basis for quantifying costs that are considered in any SCT evaluation.[48] Company competitive solicitations for DER will require the disclosure of costs by the bidders, including but not limited to capital, installation, marketing, administrative, fixed and variable O&M, lost opportunity and/or behavioral incentive costs. The Company will use the submitted costs in the project/program/portfolio BCA evaluation. Additionally, the Company will employ this information to develop and update technology specific benchmark costs as they evolve over time. .

The Participant DER Costs includes the installed cost of the device or system, as well as any ongoing operations and maintenance expenses to provide the solution. Installed costs include the capital cost of the equipment, balance of system and labor for the installation. Operating costs include ongoing maintenance expenses.

This section provides four examples of DER technologies with illustrative cost information based on assumptions that will ultimately vary given the facts and circumstances specific to each DER application:

- Solar PV – residential (4 kW)
- Combined Heat and Power (CHP) – recip engine (100 kW)
- Demand Response (DR) – controllable thermostat

[47] At 33
[48] BCA Order, Appendix pg 18

- Energy Efficiency (EE) – commercial lighting

All cost numbers presented herein should be considered representative estimates only. Actual Participant DER costs will vary by project based upon factors including:

- **Make and model:** The DER owner typically has an array of products to choose from each of which which have different combinations of cost and efficiency.
- **Type of installation:** The location of where the DER would be installed influences the capital costs, for example, ground-mounted or roof-mounted PV
- **Geographic location:** Labor rates, property taxes, and other factors vary across utility service areas and across the state

In addition, the specific DER provided herein represent a small subset of the types of DER available in the market. Utilities intend to solicit DER costs in NWAs and other competitive solicitations, and will develop utility specific costs based on experience.

For illustrative purposes, examples for four DER technologies are provided below:

7.5.4.1 Solar PV Example

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. All cost parameters in Table 7-1 for the intermittent solar PV example calculated based on information provided in the E3's NEM Study for New York ("E3 Report").[49] In this study, E3 used cost data provided by NYSERDA based on solar PV systems that were installed in NY from 2003 to 2015. For a project-specific cost analysis, actual estimated project costs would be used.

[49] 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.

TABLE 7-1. SOLAR PV EXAMPLE COST PARAMETERS

Parameter	Cost
Installed Cost (2015$/kW-AC)[50]	4,430
Fixed Operating Cost ($/kW)	15

Note: These are default values that would be used unless the DER provider supports project-specific estimates.

1. **Capital and Installation Cost:** Based on E3's estimate for NYSERDA of 2015 residential PV panel installed cost. For solar the $/kW cost usually includes both the cost of the technology and installation cost, which is the case in this example. Costs could be lower or higher depending on the size of project, installation complexity and location. This example assumes a 4 kW residential system for an average system in New York. This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in E3's NEM report.
2. **Fixed Operating Cost:** E3's estimate for NYSERDA of O&M for a residential PV panel in 2015. This estimate is applied to all New York electric utilities in the NYSERDA paper.

7.5.4.2 CHP Example

The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. Cost parameter values were obtained from the EPA's Catalog of CHP Technologies[51] for this baseload CHP example based on estimations of representative system costs. There are many site-specific factors that can effect cost parameters that are not examined in this example including: property tax, local permitting, gas and electric interconnection costs, local emissions constraints and possible structural requirements. Natural gas costs would need to be considered for the natural-gas fired CHP system.

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[50] This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in E3's NEM report.

[51] EPA CHP Report available at: https://www.epa.gov/chp/catalog-chp-technologies

TABLE 7-2. CHP EXAMPLE COST PARAMETERS

Parameter	Cost
Installed Capital Cost ($/kW)	3,000
Variable Operating Cost ($/kWh)	0.025

Note: These are illustrative estimates and would change as projects and locations are considered.

1. **Capital and Installation Cost:** EPA's estimate of a reciprocating engine CHP system capital cost. This includes of the project development costs associated with the system including equipment, labor and process capital. [52]
2. **Variable:** EPA's estimate of a 100 kW reciprocating engine CHP system's non-fuel O&M costs.[53]

7.5.4.3 DR Example

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program. The capital cost is based on an average of Wi-Fi enabled controllable thermostats from Nest, Ecobee, and Honeywell.

TABLE 7-3. DR EXAMPLE COST PARAMETERS

Parameter	Cost
Capital Cost ($/Unit)	$233
Installation Cost ($/Unit)	$115

Note: These are illustrative estimates and would change as projects and locations are considered.

1. **Capital and Installation Costs:** These costs differ by thermostat model and capabilities, and as such should be considered representative. The installation costs estimates represent a New York system, but will vary substantially depending on the program nature.

[52] EPA CHP Report. pg. 2-15.
[53] EPA CHP Report. pg. 2-17.

2. **Operating Costs:** Assumed to be $0 for the DR asset participant based on comparison with the alternative technology.

7.5.4.4 EE Example

The energy efficient lighting used in this example is indoor installation of linear fluorescent lighting in a commercial office setting. Lighting cost estimates are based on the full cost of the measure, not the incremental cost over what is currently installed.

TABLE 7-4. EE EXAMPLE COST PARAMETERS

Parameter	Cost
Installed Capital Cost ($/Unit)	$80

Note: These are illustrative estimates and would change as projects and locations are considered.

1. **Installed Capital Cost:** Based on Navigant Consulting's review of manufacturer information and energy efficiency evaluation reports.

7.5.5 Lost Utility Revenue

Lost Utility Revenue includes the distribution and other non-by-passable revenues that are shifted on to non-participating customers due to the presence of revenue decoupling mechanisms, in which sales-related revenue "losses" due to a decrease in electricity sales or demand is recovered by marginally increasing the rate of electricity sales or demand to non-participating customers.

Lost utility revenue is not included in the SCT and UCT as the reduced participant revenues are offset by the increased non-participant revenues. Therefore, this cost is only included in the RIM. As DER reduces utility sales and the associated revenues, a revenue decoupling mechanism enables the utility to be made whole by recovering these lost revenues from other ratepayers.

The impact to non-participating customers would be estimated by evaluating the type of DER and the tariffs applicable to the affected customers.

7.5.6 Shareholder Incentives

Shareholder Incentives include the annual costs to ratepayers of utility shareholder incentives that are tied to the projects or programs being evaluated.

Shareholder incentives should be project or program specific and should be evaluated as such.

7.5.7 Net Non-Energy Costs

A suggested methodology for determining this benefit is not included in this version of the Handbook. In cases where non-energy impacts are attributable to the specific project or program, they may be assessed qualitatively. Net Non-Energy Costs may be applicable to any of the cost-effectiveness tests defined in the *BCA Order* depending on the specific project and non-energy impact.

8. Characterization of DER Profiles

8.0 Overview of DER Profiles

This section discusses the characterization of DERs using several examples, and presents the type of information necessary to assess associated benefits and costs.

Four DER categories are defined to provide a useful context, and specific example technologies within each category are selected for examination. These categories are:

1. Intermittent,
2. Baseload,
3. Dispatchable
4. Load Reduction

There are numerous potential examples of individual DERs within each category, varying by technology, size, location, customer application, and other factors. A single example DER was selected in each of the four categories to illustrate specific BCA values, as shown in table 8-1 below. These four examples cover a useful, illustrative range of impacts that DERs can have on the various benefit and cost categories in the BCA Handbook.

TABLE 8-1 DER CATEGORIES AND EXAMPLES PROFILED

DER Category	DER Example Technology
Intermittent	Solar PV
Baseload	CHP
Dispatchable	Controllable Thermostat
Load Reduction	Energy Efficient Lighting

The DER technologies that have been selected as examples are shown in Table 8-2.

Each DER technology has unique operating characteristics that allow it to accrue some benefits and costs but not others. In some cases, the ability of a DER to provide certain benefits and incur certain costs will be driven by the operational objective of the specific DER, not the intrinsic characteristics of the technology itself. For example:

- DR technology in one situation may be operated to reduce the NYISO peak, which may or may not coincide with a distribution feeder peak where it is installed.
- Another DR technology may be operated to provide support for a distribution NWA, in which the distribution feeder or substation may not have a peak load that coincides with the NYISO peak.

Thus, the operational objectives of the DR technology would result in different estimates of benefits and costs depending on this operational objective. Key attributes of the example DER technologies are provided in Table 8-2.

TABLE 8-2. KEY ATTRIBUTES OF SELECTED DER TECHNOLOGIES

Resource	Attributes
Photovoltaic (PV)	PV is an intermittent resource with energy output determined by solar irradiance. The directional orientation and vertical angle of PV panels are important considerations for determining energy output and thus the corresponding coincidence factors with system-wide or local power delivery. PV energy output may also degrade over time.
Combined Heat and Power (CHP)	CHP is a resource typically sized to meet a customer's thermal energy requirements, but which also provides electrical energy. The particular customer's characteristics determine the ability of CHP to contribute to various benefit and cost categories.
Energy Efficiency (EE)	EE reduces the energy consumption for delivery of a particular service (use) without degrading or reducing the level of service delivered.
Demand Response (DR)	DR reduces energy demand for a particular service (use) during specific hours of the day—typically peak demand hours—without reducing the service to an unacceptable level. DR is typically available only for limited hours in a year (e.g., <100 hrs). The operational objective of the DR determines how it may contribute to various benefit and cost categories.

Each example DER is capable of enabling a different set of benefits and incurs a different set of costs, as illustrated in Table 8-3.

TABLE 8-3. GENERAL APPLICABILITY FOR EACH DER TO CONTRIBUTE TO EACH BENEFIT AND COST

#	Benefit/Cost	PV	CHP	DR	EE
Benefits					
1	Avoided Generation Capacity Costs	●	●	●	●
2	Avoided LBMP	●	●	●	●
3	Avoided Transmission Capacity Infrastructure	◒	◒	◒	◒
4	Avoided Transmission Losses	○	○	○	○
5	Avoided Ancillary Services	○	○	○	○
6	Wholesale Market Price Impacts	●	●	●	●
7	Avoided Distribution Capacity Infrastructure	◒	◒	◒	◒
8	Avoided O&M	○	○	○	○
9	Avoided Distribution Losses	○	○	○	○
10	Net Avoided Restoration Costs	○	○	○	○
11	Net Avoided Outage Costs	○	◒	○	○
12	Net Avoided CO_2	●	●	●	●
13	Net Avoided SO_2 and NO_x	●	●	●	●
14	Avoided Water Impacts	○	○	○	○
15	Avoided Land Impacts	○	○	○	○
16	Net Non-Energy Benefits	○	○	○	○

Costs					
17	Program Administration Costs	●	●	●	●
18	Added Ancillary Service Costs	○	○	○	○
19	Incremental T&D and DSP Costs	◒	◒	◒	○
20	Participant DER Cost	●	●	●	●
21	Lost Utility Revenue	●	●	●	●
22	Shareholder Incentives	●	●	●	●
23	Net Non-Energy Costs	○	○	○	○

Note: This is general applicability and project-specific applications may vary.

● Generally applicable ◒ May be applicable ○ Limited or no applicability

As described in Section 7, each quantifiable benefit typically has two types of parameters. The parameters to monetize the value are generally unaffected by the DER being analyzed in the BCA (e.g., AGCC in $ per MW-yr), whereas other parameters asses the magnitude of underlying benefit and may vary by type of DER (e.g., system coincidence factor). Table 8-4 identifies the parameters which are necessary to characterize DER benefits.

As described in Section 7, several benefits potentially applicable to DER require further investigation to estimate and quantify the impacts, and project-specific information before they can be incorporated into a BCA (e.g., Avoided O&M, Net Avoided Restoration Costs and Net Avoided Outage Costs, and Avoided Ancillary Services).

TABLE 8-4. KEY PARAMETER FOR QUANTIFYING HOW DER MAY CONTRIBUTE TO EACH BENEFIT

#	Benefit	Key Parameter
1	Avoided Generation Capacity Costs	**SystemCoincidenceFactor**
2	Avoided LBMP	**ΔEnergy (time-differentiated)**
3	Avoided Transmission Capacity Infrastructure	**TransCoincidenceFactor**
4	Avoided Transmission Losses	Limited or no applicability
5	Avoided Ancillary Services	Limited or no applicability
6	Wholesale Market Price Impacts	**ΔEnergy (annual), ΔAGCC**
7	Avoided Distribution Capacity Infrastructure	**DistCoincidenceFactor**
8	Avoided O&M	Limited or no applicability
9	Avoided Distribution Losses	Limited or no applicability
10	Net Avoided Restoration Costs	Limited or no applicability
11	Net Avoided Outage Costs	Limited or no applicability[54]
12	Net Avoided CO_2	**CO_2Intensity** (limited to CHP)
13	Net Avoided SO_2 and NO_x	**PollutantIntensity** (limited to CHP)
14	Avoided Water Impacts	Limited or no applicability
15	Avoided Land Impacts	Limited or no applicability
16	Net Non-Energy Benefits	Limited or no applicability

[54] A CHP system may be able to provide a Net Avoided Outage Costs benefit in certain system configurations.

Table 8-5 further describes the key parameters identified in Table 8-4.

Table 8-5. Key parameters

Key Parameter	Description
Bulk System Coincidence Factor	Necessary to calculate the Avoided Generation Capacity Costs benefit.[55] It captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability
Transmission Coincidence Factor[56]	Necessary to calculate the Avoided Transmission Capacity Infrastructure benefit. It quantifies a project's contribution to reducing a transmission system element's peak demand relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
Distribution Coincidence Factor	Distribution coincidence factor is required to calculate the Avoided Distribution Capacity Infrastructure benefit. It captures the contribution to the distribution element's peak relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
CO_2 Intensity	CO_2 intensity is required to calculate the Net Avoided CO_2 benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
Pollutant Intensity	Pollutant intensity is required to calculate the Net Avoided SO_2 and NO_X benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average SO_2 and/or NO_X emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
ΔEnergy (time-differentiated)	This parameter measures the change in bulk system energy consumed as a result of specific DER project implementation. This value is reliant on project-specific details including location. The ΔEnergy is dependent on the type of DER (e.g., intermittent vs. baseload), and how the DER would be operated (e.g., load reduction vs. energy conservation vs. backup generation). Thus, the ΔEnergy is time-differentiated. It may be appropriate to use an annual average value for some DER, while for others it may be more appropriate to use an average on-peak hours of operation, or even hourly operation. In each case the corresponding LBMP data would be required to value the benefit. The examples provided herein discuss potential approaches to consider time-differentiation by DER type.[57]

[55] This parameter is also used to calculate the Wholesale Market Price Impact benefit.
[56] Bulk transmission effectively has the same coincidence factor as generation since non-project specific transmission benefits are included in the Avoided LBMP and AGCC. This transmission coincidence factor is applicable for the Avoided Transmission Capacity Infrastructure and Related O&M benefit; which incorporates incremental value beyond what is included in the Avoided Generation Capacity Costs and Avoided LBMP benefits.
[57] Note also that annual change in bulk system energy is used in the calculation of Wholesale Market Price Impact benefit..

8.1 Coincidence Factors

Coincidence factors for DER are an important part of the benefit calculations and can be estimated in a variety of ways. What follows is a general approach for calculating the coincidence factors. Typical values are presented as examples in the sections below, however determining appropriate values for a specific project or portfolio may require additional information and calculation.

The first step is to identify the respective peak times for Bulk System, Transmission element or Distribution element as needed. Illustrations using a single peak hour are provided below.

8.1.1 Bulk System

According to the NYISO, the bulk system peaks generally occur during the afternoon hours of the hottest non-holiday weekday. The peak day might occur from May to October depending on the weather. For example, the New York Control Area (NYCA) peak typically occurs around hour ending 5 PM.

Table 8-6 below represents the NYCA peak dates and times for the last 5 years, for illustrative purposes.

TABLE 8-6. NYCA PEAK DATES AND TIMES

Year	Date of Peak	Time of Peak
2011	7/22/2011	Hour Ending 5 PM
2012	7/17/2012	Hour Ending 3 PM
2013	7/19/2013	Hour Ending 6 PM
2014	9/2/2014	Hour Ending 5 PM
2015	7/29/2015	Hour Ending 5 PM

8.1.2 Transmission

The transmission peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The peak is dependent on the location of specific transmission constraints where utility capital investment may be needed. If applicable, use the hour that the constrained element on the transmission system experiences its peak load. In general, the benefits of a reduced transmission peak would be captured through the Avoided LBMP and AGCC benefits.

8.1.3 Distribution

The distribution peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The distribution system coincidence factor is highly project specific. The distribution system serving predominantly large office buildings will peak at a different time or day than that of a distribution system that serves a residential neighborhood.

The distribution system peak may differ or coincide with the NYCA system peak and the transmission peak.

System-wide averages have been historically acceptable to use for some investment portfolios such as Energy Efficiency where the programs are broad based, and system-wide averages are provided in the Technical Resource Manual (TRM), which assumes a historical coincidence for the NYCA peak.

Going forward, for investments that are more targeted in nature, a more localized coincidence factor is likely to be appropriate. The value of reducing the distribution peak is dependent on the location of constraints in the distribution equipment where utility capital investment may be needed. Note that in some cases with very local benefits objectives, even if the coincidence factor is high, the capacity value of a DER to the distribution system may be low or zero if no constrained element is relieved (e.g., no distribution investment is otherwise required in capacity in that location, thus there is no distribution investment to be deferred even with highly coincident DER behavior).

8.2 Estimating Coincidence Factors

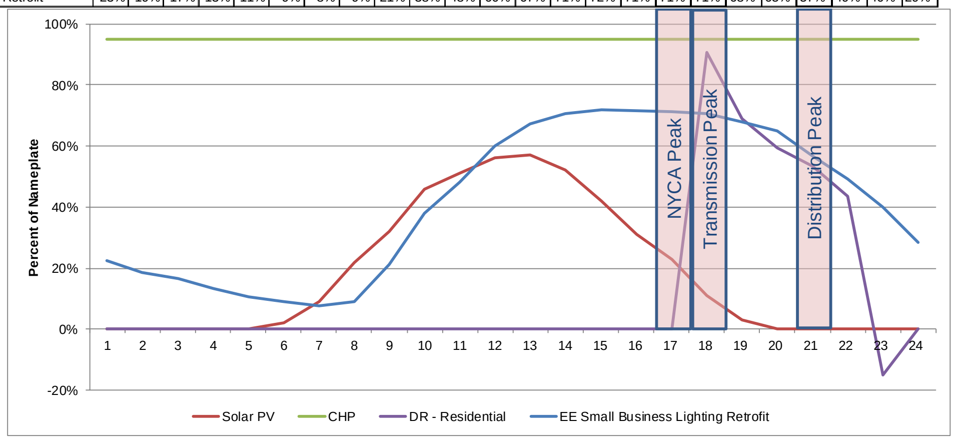
There are multiple approaches for estimating coincidence factors that apply different levels of rigor. Rigorous approaches could be defined and applied across a range of DERs; however, such an approach is likely to require a significant amount of granular information (e.g., 8760 hour load shapes for the DER projects and network information for specific locations) and time to analyze. Other approaches that require less granular information may be suitable in some cases and thus may be preferable in some situations.

One approach for estimating coincidence factors is to model the energy behavior of the DER on a time specific basis (e.g., hourly output) and normalize this behavior to the nameplate capacity. This time specific, normalized behavior can then be compared to the relevant peaks (i.e., system, transmission, and distribution) on the same time specific basis to determine the coincidence factors. The time basis can be done on an annual basis, using a ‘typical day’, or using a subset of hours that are appropriate that specific DER.

Figure 8-1 provides an illustrative plot of the hourly DER output curves for a summer peak day as a graphical demonstration of the calculation method. The y-axis represents the percentage of DER output vs. the DER nameplate, and the x-axis shows the hour of the peak day. By using the Bulk System, Transmission or Distribution peak hour and the respective percentage of peak, the coincidence factors can be determined based on the type of resource.

FIGURE 8-1. ILLUSTRATIVE EXAMPLE OF COINCIDENCE FACTORS

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Solar PV	0%	0%	0%	0%	0%	2%	9%	22%	32%	46%	51%	56%	57%	52%	42%	31%	23%	11%	3%	0%	0%	0%	0%	0%
CHP	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
DR - Residential	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	91%	69%	59%	53%	43%	-15%	0%
EE Small Business Lighting Retrofit	23%	19%	17%	13%	11%	9%	8%	9%	21%	38%	48%	60%	67%	71%	72%	71%	71%	71%	68%	65%	57%	49%	40%	29%



Source: Consolidated Edison Company of New York

The individual DER example technologies that have been selected are discussed below.[58]

The values for the DER examples have been compiled from various sources and each of these sources may apply different valuation techniques. Some sources performed extensive simulations to generate statewide averages, while others performed calculations on a variety of system specification assumptions. For example, the coincidence factors for the solar example were calculated in E3's NEM Study for New York ("E3 Report")[59] based on a simulation of a large number of solar systems across New York.

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[58] The BCA Handbook does not attempt to provide an example of a portfolio of interdependent DERs, such as those that might be procured to provide an NWA approach. Such a combination of project-specific DERs and distribution system information is less generalizable for assessing transmission and distribution coincidence factors, and less informative as an example than the individual DER examples selected. For example, when assessing NWAs it is necessary to assess their functional equivalence with traditional wired solutions. This requires understanding the potentially complex interactions between the DERs, assessing their joint reliability relative to that of traditional wired investment, and understanding the uncertainties in performance that may impact ability to maintain safe, reliable, economic energy delivery. The BCA handbook incorporates derating factors in various benefit calculations to account for these elements, but a discussion of those factors would complicate this section significantly, and so it was not included.

[59] 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.

An area for further investigation will be to assess and develop a common approach and methodology for determining the values for DER-specific parameters for each type of DER.

8.3 Solar PV Example

Solar PV is selected to depict an **intermittent** DER, where the electricity generation is dependent on the resource availability, in this case solar irradiance. The parameter assumptions and methodology used to develop those assumptions were obtained from the E3 Report.

8.3.1 Example System Description

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. These details allow for an estimate of material and installation costs, but there are several other system details required to estimate system energy output, and therefore a full benefit analysis. Local levels of solar irradiance, panel orientation (azimuth angle from north, south, east, west), tilt (typically, 0°-25° for rooftop systems located in NY) and the addition of a tracking feature, as well as losses associated with the balance of system equipment (e.g., inverters, transformers) and system degradation over time each impact the system's capacity factor and coincidence factors with the bulk system, transmission and distribution.

The impact and value of solar output on system, transmission, and distribution systems must consider the intermittent behavior of solar generation. To conduct this analysis, an hourly profile of generation based on project-specific parameters, as well as corresponding system, transmission, and distribution load profiles, provide the information that is necessary to estimate the coincidence factors for this example DER technology. The values that follow in this section are for a system-wide deployment of solar PV.

8.3.2 Benefit Parameters

The benefit parameters in Table 8-7 for the intermittent solar PV example are based on information provided in the E3 Report.

E3 determined utility-specific average values for coincidence and capacity factors. The statewide weighted-averages based on electricity delivered by utility are provided in Table 8-7. These values are illustrative estimates that may be refined as more data becomes available. To calculate project-specific benefit values, hourly simulations of solar generation, peak hours, and energy prices (LBMP) would need to be calculated based on the project's unique characteristics. Similarly, utility and location-specific specific information would be needed. For example, the distribution coincidence factor can vary significantly depending on time of the feeder and substation peak.

TABLE 8-7. SOLAR PV EXAMPLE BENEFIT PARAMETERS

Parameter	Value
SystemCoincidenceFactor	36%
TransCoincidenceFactor	8%
DistCoincidenceFactor	7%
∆Energy (time-differentiated)	Hourly

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** This value represents the 'effective' percent of the nameplate capacity, 4 kW-AC, that reduces the system peak demand, resulting in an avoided generation capacity benefit. The 36% calculated from results of the E3 Report aligns with the coincidence values presented in the NYISO ICAP manual, which provides a range from 26%-43% depending on system azimuth and tilt angle.[60] It is acceptable to use the summer average because in this BCA, the AGCC is calculated based on the summer impact on-peak load (Section 7.1.1).
2. **TransCoincidenceFactor:** The transmission coincidence factor included is for the New York average sub-transmission coincidence factor. This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the sub-transmission system.
3. **DistCoincidenceFactor:** The distribution coincidence factor is lowest. Residential distribution feeders and substations often peak during early evening hours when solar output is low.[61] This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the distribution system.
4. **∆Energy (time-differentiated):** As discussed above solar output would be higher during daylight hours and summer months. As hourly solar profiles are available from SAM, it would be appropriate to compare the projected energy output with hourly LBMPs.

[60] NYISO ICAP Manual 4, June 2016 – Summer Unforced Capacity Percentage – Solar (Fixed Tilt Arrays) – pg. 4-23

[61] E3 Report, "Based on E3's NEM Ratepayer Impacts Evaluation in California it was found (in a granular substation load analysis) that distribution peak loads are generally aligned with solar PV generation profiles in approximately 30% of the systems analyzed." PDF pg. 49.

8.4 Combined Heat and Power Example

CHP is an example of a baseload DER which typically operates during system, transmission, and distribution peaks.

8.4.1 Example System Description

CHP depicts a baseload DER where the electricity is generated at all hours, except during maintenance.

The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. In this simplified example, the 100 kW system is assumed to be small relative to the commercial building's overall electric load and thus the system operates at full electrical generating capacity at all times, except when it is down for maintenance. The example is described in EPA's Catalog of CHP Technologies (EPA CHP Report).[62]

8.4.2 Benefit Parameters

Benefit parameters for the baseload CHP example are a combination of assumptions on system use and system characteristics.

Coincidence and capacity factors are derived from the assumption that the CHP is used as a baseload DER whereby the CHP system would be running at full capacity all the time, with the exception of downtime for maintenance. Since it is not always possible to schedule downtimes, the CHP unit is assumed to provide 95% power output at all hours, assuming it is down for maintenance 5% of the year.[63]

The carbon and criteria pollutant intensity can be estimated using the EPA's publically-available CHP Emissions Calculator.[64] "CHP Technology," "Fuel," "Unit Capacity" and "Operation" were the four inputs required. Based on the example, a reciprocating engine, fueled by natural gas, 100 kW in capacity operating at 95% of 8,760 hours/year.

To complete a project-specific analysis, actual design parameters and generation profiles would be needed to assess the likelihood of coincidence, emissions, and capacity factors.

[62] https://www.epa.gov/chp/catalog-chp-technologies
[63] EPA CHP Report. pg. 2-20.
[64] EPA CHP Emissions Calculator https://www.epa.gov/chp/chp-emissions-calculator.

TABLE 8-8. CHP EXAMPLE BENEFIT PARAMETERS

Parameter	Value
SystemCoincidenceFactor	0.95
TransCoincidenceFactor	0.95
DistCoincidenceFactor	0.95
CO_2Intensity (metric ton CO_2/MWh)	0.141
PollutantIntensity (metric ton NO_X/MWh)	0.001
∆Energy (time-differentiated)	Annual average

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
4. **CO_2Intensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section 7.4.1).
5. **PollutantIntensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section 7.4.2). There are no SO_2 emissions from burning natural gas.
6. **∆Energy (time-differentiated):** Assuming the CHP is used as a baseload resource, with the exception of downtime for maintenance, capacity factor is 95%. Because it is not possible to predict when the downtime may occur, using annual average LBMP would be appropriate.

8.5 Demand Response Example

DR depicts an example of a **dispatchable** DER where the resource can be called upon to respond to peak demand.

8.5.1 Example System Description

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program.

DR is a dispatchable DER because it is reduces demand on request from the system operator or utility.[65] Each DR program has unique requirements for notification time, length of demand reduction, number of calls, and frequency of calls. A DR resource is typically available only for limited hours in a year (e.g., <100 hrs). The major benefit from DR is ability to reduce peak demand. The particular use case or operational objective of the DR determines the value for its coincidence factors.

The coincidence factors shown below do not account for load or device availability.

- Load availability is defined as the percentage of total potential capacity that can be shed from the load connected to the DR system at the time the DR event is called.
- Device availability is defined as the ability the DR system to accurately receive the DR signal and control the load.

These factors, multiplied by the total potential capacity of the DR asset, would produce the average demand reduction for the asset. Average demand reduction multiplied by the coincidence factor is then defined as the average peak coincidence demand. These values are not presented here but are project- and technology-specific and will differ substantially among DR technologies and loads. As such, project-specific analyses would need to consider the load and system availability, as well as response rate (as described above) to accurately determine the appropriate coincidence factors.

This DR example is designed to reduce system peak (consistent with most existing DR programs), thus the system coincidence factor is 1.0 such that the DR resource is called to reduce the system peak load.[66] Given the small number of calls annually, the coincidence factor with the system peak is assumed to be 1, while the coincidence factors for the transmission and

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[65] Some DR programs may be “dispatched” or scheduled by third-party aggregators.
[66] Note, the controllable load may not be operating at the time of peak.

distribution peaks is assumed to be 0.5 which is consistent with the assumption that this particular DR example is not targeted to be coincident with those peaks.[67]

As an alternative approach, to calculate the coincidence factors for a specific DR resource, comparative analysis should be performed on the most recent annual data comparing the peak demand of the targeted system with the peak demand of the other systems. Comparing the coincidence of the top 50 hours of total system load and top 50 hours of each feeder's load would produce the distribution coincidence factor for a DR project that targets system peak. Analysis should be based on data from the Day-Ahead Market or Real-Time Market depending on the design of the DR program. Coincidence factors for DR projects should use the most recently available data.

The value of reduced energy use attributable to the DR asset can be calculated using the average LBMP of the top 50 hours of system peak. A more accurate energy calculation would consider the expected number of times that DR was called in a given year as well as the length of the calls beyond the peak hour itself (e.g., 2 hour events, 4 hour events). This calculation will differ if the DR asset is intended to defer another peak, or if the DR program has a substantially different frequency of calls. The number of hours averaged should be based on the frequency of DR calls and the selection of those hours should be based on when the DR calls will be made.

8.5.2 Benefit Parameters

The benefit parameters described here are assumed based on the example and considerations described above.

TABLE 8-9. DR EXAMPLE BENEFIT PARAMETERS

Parameter	Value
SystemCoincidenceFactor	1.0
TransCoincidenceFactor	0.5
DistCoincidenceFactor	0.5
∆Energy (time-differentiated)	Average of highest 100 hours

Note: These are illustrative estimates and would change as specific projects and locations are considered.

[67] Con Edison Callable Load Study, Page 78, Submitted May 2008. http://www.coned.com/documents/Con%20Edison%20Callable%20Load%20Study_Final%20Report_5-15-08.pdf.

1. **SystemCoincidenceFactor:** The system coincidence factor is assumed to be 1.0, based on the assumption that the DR system is called upon at the time of system peak.
2. **TransCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5 but would be greater if the DR is dispatched to target the transmission peak.[68] Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above.
3. **DistCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5 but would be greater if the DR is dispatched to target the transmission peak.[69] Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above. If instead the DR asset were used to defer distribution capacity, the coincidence factor could be as high as 1 (though the system coincident factor could then be as low as zero, since if the peak periods were to occur at the same time, the project could only be dispatched for one program).
4. **∆Energy (time-differentiated):** DR would be dispatched a limited number of hours during the year. NYISO may only call upon DR for ~50 hours in a year. The energy savings can be estimated based on the *average* demand savings (not peak) expected over the hours called, times the number of hours the DR resource is expected to be called. This average reduction would be multiplied by an appropriately time-differentiated LBMP.

8.6 Energy Efficiency Example

Energy efficient lighting depicts a **load-reducing** DER where the use of the technology decreases the customer's energy consumption as compared to what it would be without the technology or with the assumed alternative technology. The parameter assumptions, and methodology used to develop those assumptions, developed using the NY TRM.[70]

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[68] Con Edison Callable Load Study, Page 78, Submitted May 2008. http://www.coned.com/documents/Con%20Edison%20Callable%20Load%20Study_Final%20Report_5-15-08.pdf.

[69] Con Edison Callable Load Study, Page 78, Submitted May 2008. http://www.coned.com/documents/Con%20Edison%20Callable%20Load%20Study_Final%20Report_5-15-08.pdf.

[70] New York State Technical Resource Manual (TRM)l: New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Version 4, Issued on April 29, 2016 – Lighting operating hour data is sourced from the 2008 California DEER Update study.

8.6.1 Example System Description

The energy efficient lighting used in this example is indoor installation of linear fluorescent lighting in a commercial office setting with an estimated utilization of 3,013 hours/year.[71] The peak period for this example is assumed to occur in the summer during afternoon hours.

EE, including lighting, is a load reducing because it decreases the customers' energy consumption and load shape, which in turn, reduces the system, transmission and distribution peak. This example of an indoor, office-setting lighting system assumes that the coincidence factor is calculated during operational hours when the load reduction due to this lighting technology is expected to occur at the time of the system peak, as well as the during the transmission and distribution peaks.

8.6.2 Benefit Parameters

The benefit parameters described here were developed using guidance from the NY TRM.

TABLE 8-10. EE EXAMPLE BENEFITS PARAMETERS

Parameter	Value
SystemCoincidenceFactor	1.0
TransCoincidenceFactor	1.0
DistCoincidenceFactor	1.0
∆Energy (time-differentiated)	~7 am to ~7 pm weekdays

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 1.0 under the assumption that the system peak occurs while standard office lighting systems are operating.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 1.0 under the assumption that the transmission system peak occurs while standard office lighting system are operating.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 1.0 under the assumption that the distribution system peak occurs while standard office lighting systems are operating.

[71] Ibid.

4. **∆Energy (time-differentiated):** This value is calculated using the lighting hours per year (3,013) as provided for General Office types[72] in the NY TRM, divided by the total hours in a year (8,760). This time period is subject to building operation, which is roughly between 7 am and 7 pm, 5 days a week, 52 weeks a year. This would define the corresponding period for determining an average LBMP that would be used to calculate the benefit.

[72] New York State Technical Resource Manual (TRM)l: New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Version 4, Issued on April 29, 2016 - pg. 221

9. Utility-Specific Data

9.0 Overview of the Companies Utility-Specific Data

This section includes utility specific data. Each data point represents a parameter that is used throughout the benefit and cost methodologies described in Section 7.

The Companies specific data values are contained within this section; along with the data source reference.

9.1 Cost-Of-Capital

The utility cost-of-capital data is included in **9-1.**

TABLE 9-1 UTILITY COST OF CAPITAL

	Cost of Capital
NYSEG	6.68%
Source: New York State Electric and Gas Case No. 15-E-0283 Joint Proposal	
RG&E	7.55%
Source: Rochester Gas and Electric Corporation Case No. 15-E-0285 Joint Proposal	

9.2 Line Losses

Utility-specific system average line loss data is shown in Table 9-2.

Losses percentages come from utility-specific loss studies.

TABLE 9-2 UTILITY LINE LOSS DATA

	Loss Factor	Service Classification
NYSEG		
Sub-Transmission	1.50%	3S, 7-3
Primary Distribution	3.77%	3P, 7-2
Secondary Distribution	7.28%	1,2,6,7-1,8,9,12 (and outdoor/Street Lighting)
NYSEG and RG&E T&D Losses 7/17/2008 Case 08-E-0751		
RG&E		
Primary Distribution	4.91%	3,8,9
Secondary Distribution	6.93%	1,2,3,4,6,7,8,9,SL
NYSEG and RG&E T&D Losses 7/17/2008 Case 08-E-0751		

9.3 Marginal Cost-of-Service

Utility-specific system average marginal costs of service are found in 9-3.

9-3 UTILITY SYSTEM AVERAGE MARGINAL COSTS OF SERVICE

	Transmission	Primary Distribution	Secondary Distribution
NYSEG	$4.18/kW-yr	$12.43/kW-yr	$18.41/kW-yr
Source: NYSEG Marginal Cost of Electric Delivery Service 5/11/2015 filed in New York State Electric and Gas Case No. 15-E-0283			
RG&E	$3.25/kW-yr	$8.16/kW-yr	$23.42/kW-yr
Source: Rochester Gas and Electric Corporation Marginal Cost of Electric Delivery Service 10/23/2015 filed in Rochester Gas and Electric Corporation Case No. 15-E-0285			

9.4 System Average Reliability

Utility-specific system 5-year average system reliability metrics are found in 9-4.

Utility-specific 2014 Outage Event Types for the system are shown in 9-5.

Utility-specific Average Restoration Costs are shown in 9-6.

TABLE 9-4 FIVE YEAR AVERAGE UTILITY SYSTEM RELIABILITY METRICS

Parameter	Units	Value
NYSEG		
Number of Interruptions	int	9,884
Number of Customer-Hours	cust-hours	1,858,379
Number of Customers Affected	cust-int	933,821
Number of Customers Served	cust	858,458
Average Duration Per Customer Affected (CAIDI)	hours/int	1.99
Average Duration Per Customers Served (SAIDI)	hrs/cust/yr	2.16
Interruptions Per 1000 Customers Served	int/1k cust	11.51
Number of Customers Affected Per Customers Served (SAIFI)	int/cust/yr	1.09
RG&E		
Number of Interruptions	int	3,017
Number of Customer-Hours	cust-hours	493,074
Number of Customers Affected	cust-int	276,345
Number of Customers Served	cust	364,822
Average Duration Per Customer Affected (CAIDI)	hours/int	1.78
Average Duration Per Customers Served (SAIDI)	hrs/cust/yr	1.36
Interruptions Per 1000 Customers Served	int/1k cust	8.29

Number of Customers Affected Per Customers Served (SAIFI)	int/cust/yr	0.76
Source: NY DPS Electric Reliability Performance Report. Five-year average, 2010-2014		

TABLE 9-5 2014 OUTAGE EVENT TYPES FOR UTILITY SYSTEM

Outage Type	%
NYSEG	
Tree Contacts	43.3%
Lightning	11.0%
Equipment Failures	15.0%
Accidents	18.0%
Overloads	2.7%
Other	10.0%
RG&E	
Tree Contacts	23.4%
Lightning	9.2%
Equipment Failures	28.2%
Accidents	19.0%
Overloads	1.4%
Other	19.8%
Source: NY DPS Electric Reliability Performance Report. Five-year average, 2010-2014	

TABLE 9-6 AVERAGE RESTORATION COSTS

	Average Restoration Costs
NYSEG	Restoration Costs will be determined for each specific project as applicable
RG&E	Restoration Costs will be determined for each specific project as applicable
Source: Project-Specific	

9.5 Operation & Maintenance Costs

The utility Operation & Maintenance Cost data is included in **9-7.**

TABLE 9-7 UTILITY OPERATION & MAINTENANCE COSTS

	Operation & Maintenance Costs
NYSEG	O&M Costs will be determined for each specific project as applicable
RG&E	O&M Costs will be determined for each specific project as applicable
Source: Project Specific	

9.6 Restoration Costs

The utility Restoration Cost data is included in **9-8.**

TABLE 9-7 RESTORATION COSTS

	Restoration Costs
NYSEG	Restoration Costs will be determined for each specific project as applicable
RG&E	Restoration Costs will be determined for each specific project as applicable
Source: Project Specific	

9.7 System NYISO, ICAP and Ancillary Services Zones

Utility-specific NYISO, ICAP and Ancillary Services Zones are shown in 9-8.

TABLE 9-8 NYISO ZONES THE COMPANIES SERVE

NYISO Zones	NYISO Zones	ICAP Zone	Ancillary Services Zone
NYSEG			
	A - West	Rest of State (ROS)	WEST
	C - Central	Rest of State (ROS)	WEST
	D - North	Rest of State (ROS)	EAST
	E – Mohawk Valley	Rest of State (ROS)	EAST/WEST (locational dependent)
	F - Capital	Rest of State (ROS)	EAST/WEST (locational dependent)
	G - Hudson Valley	Lower Hudson Valley (LHV)	SOUTH EAST NY (SENY)
	H - Millwood	Lower Hudson Valley (LHV)	SOUTH EAST NY (SENY)
RG&E			
	B - Genesee	Rest of State (ROS)	WEST
Source: NYISO			