Methods, Tools and Resources:

A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis

March 2022

Companion Guide to the *National Standard Practice Manual*

NATIONAL ENERGY SCREENING PROJECT

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National Energy Screening Project

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The MTR handbook is a companion document to the 2020 *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, which presents the NSPM Benefit-Cost Analysis (BCA) Framework, fundamental BCA principles, and guidance specific to determining primary and secondary BCA tests.

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This MTR handbook and related materials, including prior NSPM publications, are available at:
www.nationalenergyscreeningproject.org/national-standard-practice-manual/

GLOSSARY

Ancillary services: services required to maintain electric grid stability. Typically include frequency regulation, voltage regulation, spinning reserves, and operating reserves, either traded in wholesale energy markets or self-supplied by utilities.

Average costs: the cost of producing a product divided by the number of products produced.

Avoided costs: the costs of those electricity and gas resources (e.g., generation, transmission, and distribution system infrastructure) that are deferred or avoided by the DERs being evaluated for cost-effectiveness.

Benefit-cost analysis: a systematic approach for comparing the benefits and costs of alternative options to determine whether the benefits exceed the costs over the lifetime of the program or project under consideration.

Best available: information that is based on acceptable standards of accuracy, reliability, and relevancy, is up-to-date and mindful of limitations, is peer-reviewed when appropriate and required, and delivered at an appropriate time in the decision-making process.

Bill impact analysis: indicates the extent to which customer bills are affected for customers that participate in DER programs and those who do not.

Building electrification: substituting electricity for consumption of other fuels, e.g., space heating, water heating, cooling, cooking, drying, and other end-uses, therefore increasing electric system costs.

Cost-effectiveness: when investment in a resource is worthwhile; measured by the benefits of investing in a resource being greater than the costs of investing therein.

Demand flexibility: the capability provided by DERs to reduce, shed, shift, modulate, or generate electricity; energy flexibility and load flexibility are often used interchangeably with demand flexibility.

Demand response: Demand response programs reduce or shift electricity or gas usage during peak periods in response to time-based rates or other forms of financial incentives. Demand response programs are used by some electric system planners and operators as resource options for balancing supply and demand. (NERC 2011)

Discount rates: a component of cost-effectiveness analysis which reflects a "time preference"—the relative weight given to short- versus long-term impacts. A higher discount rate gives more weight to short-term benefits and costs relative to long-term benefits and costs, while a lower discount rate gives greater weight to long-term impacts.

Dispatchable: means that the timing and level of response is under the control of the utility, either through technical control or by the terms of a contract, or both.

Distributed energy resource: electricity and gas resources sited close to customers that can provide all or some of their immediate power needs and/or can be used by the utility system to either reduce demand or provide supply to satisfy the energy, capacity, or ancillary service needs of the grid. These include energy efficiency, demand response, distributed generation, storage, plug-in electric vehicles, strategic electrification technologies, and more.

Distributed generation: electric generation interconnected to the distribution grid and operating at the distribution level, generally near a load, though sometimes stand-alone. Distributed generation includes distributed solar photovoltaic (PV/DPV) technology, combined heat and power, district heating and cooling, small wind, and biomass and biogas facilities associated with landfills and agricultural operations.

Distributed storage: technologies used to locally store energy. This handbook primarily focuses on BTM resources, such as lithium-ion batteries, but it can also apply more broadly to all distributed storage types (e.g., thermal, including electric water heaters) and chemistries (e.g., lead-acid) as opposed to those connected at transmission (e.g., pumped hydro and compressed air).

Effective useful life (EUL): the average time over which a DER measure results in energy savings (or use) including the effects of equipment failure, removal, and cessation of use.

Electric vehicle (EV): a vehicle powered directly by electricity rather than other fuels. These can also in some instances operate as storage devices.

Electrification: increased electrification of end-uses, when beneficial to the utility system as a whole, including the increased integration of electrification including building electrification and electric vehicles. This can be "partial," where some but not all fuel consumption is replaced by electricity (e.g., a plug-in hybrid electric vehicle), or "complete" (e.g., a battery electric vehicle).

Energy efficiency (EE): Resources that include technologies, services, measures, or programs that reduce energy consumption by host customers and that are funded by, promoted, or otherwise supported on behalf of all electricity and gas utility customers.

Greenhouse gas (GHG) emissions: gases that trap heat in the atmosphere (including carbon dioxide, methane, nitrous oxide, and fluorinated gases) emitted from human activities, primarily burning fossil fuels for electricity generation, transportation, industrial processes, commercial and residential heating, and agriculture.

Host customer: The owner/occupant of the site at which BTM DERs are installed and/or operated. In some cases, these are program participants, e.g., participants in a demand response or energy efficiency program. In other cases, where there is no program, e.g., electric vehicle owners, 'customer' refers to these consumers being a customer of a utility.

Incremental analysis: consists of changes that will occur as a result of the DER relative to a scenario where the DER is not in place.

Integrated distribution planning (IDP): a long-run utility planning process that expands on traditional distribution planning and allows for evaluation of both traditional distribution resources and DERs for meeting distribution grid needs.

Integrated grid planning (IGP): a long-run planning process for vertically integrated utilities that evaluates all resource types (DERs and utility-scale resources) to enable optimization across all levels of the utility system (generation, transmission, and distribution).

Integrated resource planning (IRP): a long-run planning process for vertically integrated utilities that evaluates DERs and utility-scale generation for meeting peak and energy demands.

Long-run: a period in which all costs are essentially variable, including capital costs. Long-run costs include all costs incurred over the full BCA study period, including short-run costs plus all capital investments needed to increase production capacity to meet customer demand.

Lost revenues: occur when DERs reduce consumption of electricity or gas, which can result in fixed costs being spread across a smaller volume of sales, putting upward pressure on rates.

Impacts: both the benefits and the costs of a supply-side or demand-side resource.

Jurisdictions: states, provinces, utilities, municipalities, or other regions for which DER resources are planned and implemented.

Jurisdiction-Specific Test (JST): the primary test created by a jurisdiction following use of the NSPM BCA Framework. It embodies all of the key principles of cost-effectiveness analyses and accounts for that jurisdiction's applicable policy goals by including impacts identified as relevant to that jurisdiction's goals and objectives.

Levelized costs: the average cost per unit of energy required to install and operate an electricity or gas resource over its operating life, taking into account the time value of money. The costs of electricity and gas resources, including DERs, can be put into levelized costs to allow for a relatively simple, direct comparison across different resources.

Marginal costs: the change in per-unit costs as the result of a small change in output.

Microgrid: a group of interconnected loads and DERs within clearly defined electrical boundaries. A microgrid can act as a single controllable entity with respect to the grid and can connect or disconnect from the grid to operate as either grid-connected or an "island."

Multiple-DER analysis: when multiple-DER types are assessed and evaluated relative to a static set of alternative resources. This approach is more complex than single-DER analysis and is designed to capture the interactive effects of DERs on one another. Multiple-DER analysis can be applied in context of a customer site (e.g., grid-interactive efficient buildings), for a certain geographic area to identify non-wires solutions, and/or across the entire utility system.

Non-dispatchable: refers to programs and measures without such controls and includes time-varying rates that send price signals to encourage customers to alter their energy usage during particular hours.

Non-energy impacts: are impacts of DERs other than direct energy and demand impacts. While these impacts can be non-energy benefits and related costs, most are considered benefits (non-energy benefits, or NEBs). Examples include reduced emissions, comfort and productivity improvements, local macroeconomic development, and reduced risk of utility service disruptions or price spikes.

Non-pipes alternative: also known as non-pipes solution (NPS), alternatives to meeting on-system natural gas demand that delay or avoid the need for investment in traditional resources such as pipelines, storage capacity, winter-peaking services, and distribution system infrastructure.

Non-wires alternative: also known as non-wires solution (NWS), geotargeting, and market-based alternative or solution. This is a strategy of deploying DERs in a specific geographic area for the purpose of deferring or avoiding new investments in equipment, distribution, or transmission lines.

Participant Cost Test (PCT): a cost-effectiveness test that includes the benefits and costs experienced by host customers.

Participation impacts: indicate impacts participating customers will experience from participating in a DER program, in terms of bill reductions or increases.

Primary cost-effectiveness test: the cost-effectiveness test that a jurisdiction uses to determine whether a DER (or set of DERs) has benefits that exceed costs, and therefore merits acquisition or support from utilities or other energy providers.

Rate, bill, participation analysis: indicates the extent to which customers will be affected by DERs, and the extent to which DER investments might lead to distributional equity or cost allocation concerns.

Rate impact analysis: assessment of the extent to which investing in a resource will impact customer rates, sometimes in the form of a Ratepayer Impact Measure (RIM) test. This is a separate type of analysis from cost-effectiveness, which assesses whether the benefits of investing in a resource outweigh the costs.

Regulators and other decision-makers: entities including institutions, agents, or other decision-makers that are authorized to determine utility resource cost-effectiveness and funding priorities, and to oversee and guide DER analyses. Such institutions or agents include public utility commissions, legislatures, boards of publicly owned utilities, the governing bodies for municipal utilities and cooperative utilities, municipal aggregator governing boards, and more.

Regulatory perspective: the perspective of regulators or other agents that oversee resource investment choices, including energy generation and T&D infrastructure. This perspective is guided by the jurisdiction's energy and other applicable policy goals—whether in laws, regulations, organizational policies, or other codified forms—under which it operates.

Short-run: the costs that occur before capital investments are made to increase production capacity.

Single-DER analysis: when one DER type is assessed in isolation from other DER types and is evaluated relative to a static set of alternative resources.

Social Cost of Carbon: the dollar value of the net cost to society from adding an incremental amount of greenhouse gas emissions to the atmosphere in a particular year, typically estimated using the damage cost approach.

Societal Cost Test (SCT): a cost-effectiveness test, as provided in the 2001 *California Standard Practice Manual*, which includes the benefits and costs experienced by society.

Symmetry: a key principle for the treatment of benefits and costs which is necessary to avoid bias toward any one resource, whereby both benefits and costs are included (or excluded) for each relevant impact. If each type of impact is not treated symmetrically, the result will be a sub-optimal selection of resources.

Time-varying rates: Rate designs that provide different price signals to customers at different times of the day, season, or year, based on differences in underlying costs to the system.

Total Resource Cost Test (TRC): a cost-effectiveness test that includes the benefits and costs experienced by the utility system, plus benefits and costs to the program participants.

Utility: any entity that funds or otherwise supports DERs and is subject to or undertakes a cost-effectiveness analysis to inform investment decisions. This includes investor-owned utilities; publicly owned utilities; municipal utilities; cooperative utilities; federal, state, and local governments; non-governmental organizations; and others.

Utility Cost Test (UCT): a cost-effectiveness test includes the benefits and costs experienced by the utility system. This test is also known as a Program Administrator Cost Test (PACT).

Utility system: all elements of the electricity or gas system necessary to deliver services to the utility's customers. For electric utilities, this includes generation, transmission, distribution, and utility operations. For gas utilities, this includes transportation, delivery, fuel, and utility operations. This term refers to any type of utility ownership or management, including investor-owned utilities, publicly owned utilities, municipal utility systems, cooperatives, etc.

Value of lost load: a dollar value of the cost of unserved energy during power outages.

ACRONYMS

BCA	Benefit-cost analysis
BCR	Benefit-cost ratio
BEV	Battery electric vehicle
BTM	Behind the meter
BTU	British thermal units
C&I	Commercial and industrial
CES	Clean energy standard
COP	Coefficient of performance
CPS	Clean peak standard
DCFC	Direct-current fast chargers
DER	Distributed energy resources
DG	Distributed generation
DPV	Distributed solar photovoltaic
DSP	Distribution system planning
EE	Energy efficiency
EM&V	Evaluation, measurement, and verification
EV	Electric vehicle
GHG	Greenhouse gas
GWP	Global warming potential
HVAC	Heating, ventilation, and air conditioning
IDP	Integrated distribution planning
iDSM	Integrated demand-side management
IOU	Investor-owned utilities
IRP	Integrated resource planning
ISO	Independent system operator
ISO-NE	ISO New England
ITC	Federal Investment Tax Credit
LCOE	Levelized cost of energy or electricity
LCSE	Levelized cost of saved energy
LED	Light-emitting diode
LSE	Load-serving entity
MAC	Marginal abatement cost
MISO	Midcontinent Independent System Operator
MMBtu	Million British thermal units
MW	Megawatt
MWh	Megawatt-hour
NEIs	Non-energy impacts
NEM	Net energy metering
NWA	Non-wires alternative
NYISO	New York Independent System Operator
O&M	Operations and maintenance
PJM	PJM Interconnection LLC
PV	Solar photovoltaic
REC	Renewable energy credit
RPS	Renewable portfolio standard
RTO	Regional transmission organization
SCC	Social Cost of Carbon
TOU	Time of use
T&D	Transmission and distribution
VAR	Voltage levels and reactive power
VDER	Value of distributed energy resources
VOLL	Value of lost load

1. INTRODUCTION

1.1. Purpose

The *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (see NSPM 2020) provides guidance on how to determine primary and secondary tests to assess the cost-effectiveness of distributed energy resources (DERs). It provides a framework for determining which DER costs and benefits should be included in benefit-cost analyses (BCAs) given a jurisdiction's policy goals and includes guidance on conducting BCAs of single and multiple types of DERs.

> While the NSPM can be used to determine *which* DER costs and benefits to include in DER BCAs, this MTR handbook can help determine *how* to calculate the values of those costs and benefits.

This *Methods, Tools & Resources Handbook* ('MTR handbook') builds on the NSPM as a companion document by helping users identify and understand the methods, tools, and resources that can be used to calculate the benefits and costs of DERs. While NSPM can be used to determine *which* DER costs and benefits to include in DER BCAs, this MTR handbook can be used to determine *how* to calculate the values of those costs and benefits.

This MTR handbook is intended to be a reference guide for anyone preparing a BCA for DERs, including utilities, regulators and regulatory staff, state energy offices, evaluators, practitioners, consultants, and other stakeholders in the DER regulatory process. It is also intended to provide guidance for parties that review, critique, and comment on utility BCAs.

The methods, tools, and resources provided in this MTR handbook are based on currently available resources and information, which are likely to evolve over time. The National Energy Screening Project intends to update this MTR handbook periodically as new materials become available.

1.2. Applicability

Consistent with the NSPM, this MTR handbook is intended to be relevant to a variety of DER programs, procurements, or pricing mechanisms that are funded, acquired, or otherwise supported by utilities or other entities on behalf of electric or gas customers (see NSPM 2020, pages ii-iii). The document is intended to be applicable to DER programs being deployed in many organizational and jurisdictional contexts, including:

1. Any jurisdiction where DERs are implemented by utilities or other entities.
2. All ownership models of electric and gas utilities, including investor-owned, publicly owned, and cooperative utilities.
3. All types of electric utilities regardless of the services provided, including utilities that are vertically integrated, transmission- and distribution-only, distribution-only, or those serving as a distribution platform for host customers to access a variety of energy services and DERs from third parties.
4. Other entities using utility customer funds or other public funds to implement DERs, such as state energy offices and third-party program administrators.

1.3. Overview

Table 1 provides an overview of the information presented in this MTR handbook.

Table 1. Summary of chapter information

Chapter	Description
1. Introduction	The purpose and applicability of this MTR handbook
2. Key Steps for Calculating BCA Impacts	An overview of the key steps that can be used to calculate BCA inputs; describes important concepts such as how to develop Reference and DER Cases and why it is important to use long-run marginal impacts of DERs
3. Electric Utility System Impacts	How to calculate DER impacts that affect the electric utility system; these can be the result of an electric DER or of a gas DER that affects electric end-uses
4. Gas Utility System Impacts	How to calculate DER impacts that affect the gas utility system; these can be the result of a gas DER or of an electric DER that affects gas end-uses
5. Other Fuel System Impacts	How to calculate the impacts on other fuels (e.g., oil, propane, wood, gasoline) that result from electric or gas DERs
6. Host Customer Impacts	How to calculate the impacts of DERs on the customers who install them
7. Societal Impacts	How to calculate the societal impacts of electric or gas DERs
8. Reliability and Resilience	How to account for reliability and resilience for electric or gas DERs
9. Energy Equity	A conceptual framework for how to combine BCAs with distributional equity analyses to assess equity in DER investment decisions
10. Risk	A conceptual framework for how to account for risk and uncertainty when conducting a BCA for DERs
11. DER Load Impact Profiles	How to calculate load impact profiles, i.e., operating profiles, for DERs, which are necessary for determining many of the DER impacts
12. Resources	A list of all the tools, websites, and documents cited in this MTR handbook

Chapters 3 through 10 follow the same structure. For each impact addressed in each chapter, the following information is provided:

- A brief description of the impact.
- A discussion of the methods that can be used to calculate the value of the impact.
- A set of references and resources available for further information on those methods. This includes only the references specific to the relevant impact. A full list of all the references used in this MTR handbook is presented in Chapter 12.

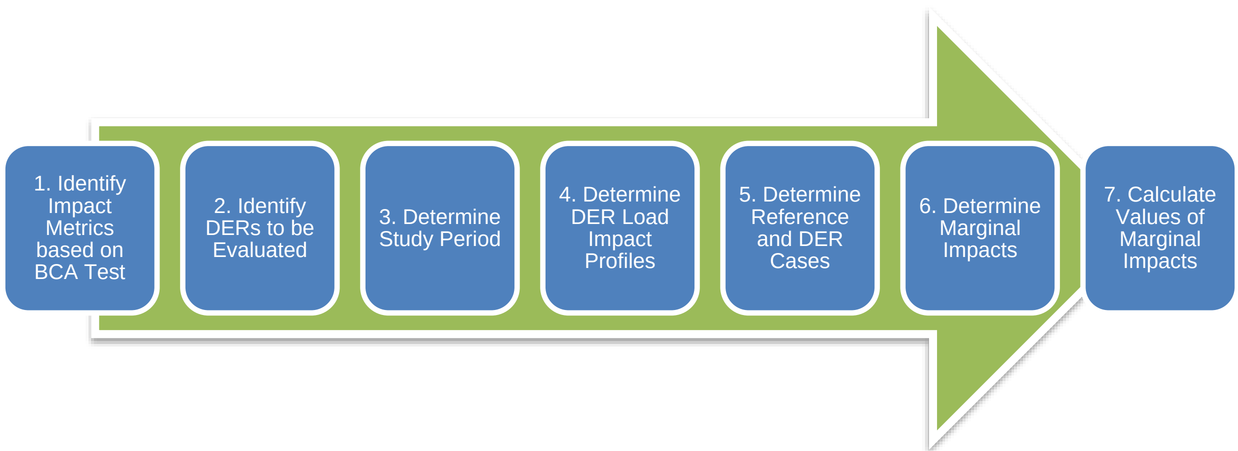
2. Key Steps for Calculating BCA Impacts

2.1. Overview

The NSPM for DERs (NSPM 2020) provides guidance on how to determine primary and secondary tests to use for BCAs. It provides a framework for determining what types of impacts should be included in BCAs per the fundamental NSPM BCA Principles, including consistency with a jurisdiction's policy goals and objective (see NSPM 2020). Establishing a jurisdiction's BCA test(s) is the first of many steps to assessing cost-effectiveness.

Once a jurisdiction has defined its BCA test and the impacts to be accounted for, there are multiple steps necessary to calculate the impacts to input in a BCA. Figure 1 summarizes the process for developing or quantifying the costs and benefits of DER investments. Each section in this chapter provides a brief discussion of each step in Figure 1. These steps are useful for understanding the descriptions of the methods that are provided in Chapter 3 through Chapter 10.

Figure 1. Key steps for calculating BCA values



2.2. Identify Impact Metrics

Once the impacts to be included in the BCA test are identified, then the metrics for estimating the impacts can be determined. For most impacts this is straightforward. For example, the metric for electric energy impacts is megawatt-hours (MWhs); the metric for electric capacity impacts is megawatts (MW); the metric for gas impacts is therms or million British thermal units (MMBtus); the metric for greenhouse gas (GHG) impacts is tons of GHG emissions. For some impacts the choice of metrics is less obvious. For example, estimates of reliability and resilience impacts might rely upon a variety of different metrics, such as system average interruption duration index, hours to restore service, and more (see Chapter 8).

These metrics can be applied to the marginal DER impacts to determine the dollar value of the impact. For example, the DER energy savings (in MWh) can be multiplied by the marginal energy impact (in $/MWh) to determine the monetary energy value (in $).

2.3. Identify the DERs to Be Evaluated

A key initial step is to identify the types of DERs to be analyzed in a BCA, i.e., whether energy efficiency, demand response, distributed generation, storage, electrification, electric vehicles, or some combination of these DERs. It is also important to initially establish the scale of the DERs to be analyzed, i.e., the approximate capacity (MW) and energy (MWh or MMBTU) of each DER type, in each year assessed.

The type and magnitude of DERs to be assessed will have important implications for determining DER load impact profiles (see Section 2.5), for determining the DER case (see Section 2.62.5), and for determining marginal impacts (see Section 2.7).

2.4. Determine the Study Period

The BCA study period is the number of years over which benefits and costs will be analyzed. The study period should be long enough to include the full operating life of the DERs being analyzed. This approach is necessary to account for all the benefits and costs of the DERs (see NSPM 2020, page 2-7).

For example:

- For a BCA of an energy efficiency plan that includes three years of energy efficiency installations, the study period should include the three years of the installations plus enough years to span the lifetime of the energy efficiency measures with the longest life. If the longest life is 20 years, then the study period should include at least 23 years to capture the full impacts of the energy efficiency measures installed in the third year.
- For a BCA of a one-year distributed solar photovoltaic (PV) program with a 25-year operating life, the study period should be 25 years. For a BCA of a 10-year distributed PV installation program, the study period should be 35 years to capture the full impacts of the PV installed in the 10th year of the program.

2.5. Determine DER Load Impact Profiles

The term "load impact profile" is used here to indicate a DER's hours of operation as well as the magnitude of the energy and capacity impacts produced in those hours. Since load impact profiles can vary widely for different DERs and the value of the DER resource can vary over different seasons of the year, days of the week, hours of the day, and even within shorter periods of time, defining DER load impact profiles is often required to determine DER utility, host customer, and societal impacts.

Load impact profiles can vary widely for different DERs, and the value of the DER resource can vary over different seasons of the year, days of the week, hours of the day, and even within shorter periods of time.

For example, some energy efficiency resources might reduce customer demand consistently every hour of the year, while other energy efficiency resources might reduce demand only during peak periods of the day or year. As another example, the load impact profile for storage technologies might vary significantly depending upon whether they are controlled by the utility or the host customer, and, if the latter, depending upon the host customer's rate design.

Combinations of multiple DER types might also lead to different load impact profiles than if they were installed separately. For example, a storage technology might have a very different load impact profile if it is paired with a distributed PV resource, because the customer might charge the storage resource when PV output exceeds onsite energy needs rather than charging it when energy prices are low. Similarly, the typical load impact profiles of electric vehicles added to the system will be very different if they are uncontrolled than if they are enrolled in a managed charging demand response program.

Some DER types are highly dispatchable while others are not. For example, distributed PV resources and many energy efficiency resources are not dispatchable, while storage and some demand response resources are highly dispatchable. Further, some DERs might be dispatched in response to customer interests while others might be dispatched to meet the short-term peak demands of the electricity grid.[1]

Ideally, DER load impact profiles would be developed on an hourly basis for each year of the BCA study period. Some DERs, such as distributed PV and storage resources, are likely to operate at very different levels throughout the day, which requires hourly information to capture the actual impacts at those different levels of operation. Other DERs, such as some energy efficiency and demand response resources, might not require hourly marginal impacts and load impact profiles; in which case it might be sufficient to use averages for key sub-annual periods, such as winter and summer or on- and off-peak periods.

Chapter 11 provides a detailed discussion of how to develop load impact profiles for different DER types and combinations of DER types.

2.6. Determine Reference and DER Case Assumptions

In general, BCAs require a comparison of two scenarios: one without the proposed DERs (the Reference Case)[2] and one with the proposed DERs (the DER Case). The difference in the incremental costs and benefits between the two cases indicates the *marginal impacts* of the DERs included in the DER Case. Understanding this construct of taking the difference between two scenarios is foundational to many of the methodologies described in this MTR handbook.

Understanding this construct of taking the difference between a Reference Case and DER Case scenario is foundational to many of the methodologies described in this handbook.

In general, the Reference Case should be based on the most likely forecast of customer demand, except that it should not include the effects on customer demand of the DERs being evaluated in the BCA. This case should, however, account for the impacts of all DERs that have already been installed, and future DERs that are not being analyzed in the BCA. For example, a BCA that seeks only to determine the value of energy efficiency should include the expected impacts from electric vehicle and distributed solar adoption in the Reference Case load forecast.

1 Ideally, rate design elements such as demand charges and time-of-use rates should be structured to encourage customers to operate their DERs in a way that would address the short-term peak demands on the electricity grid. In such cases, there would be no difference in the DER load impact profile. In practice, however, it is often the case that rate designs do not exactly reflect the short-term peak demands on the electricity grid, which would result in different load impact profiles depending upon who controls and operates the DER.

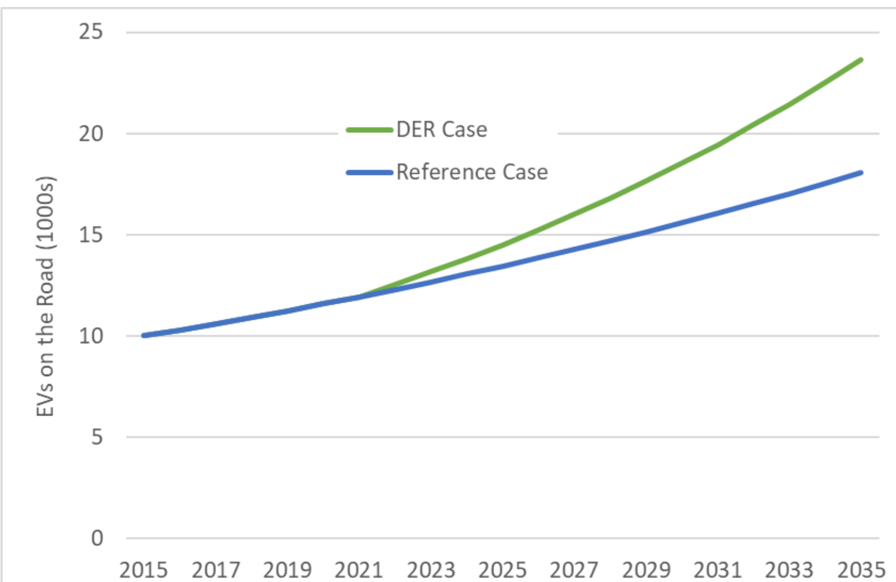
2 The Reference Case is sometimes referred to as a Business-as-Usual Case or a Baseline Case. This handbook uses the term "Reference Case" because it more generically refers to a case that is designed to be compared with a DER Case.

In addition, it is important that the Reference Case properly account for *all* the DERs that might occur in the absence of the DER program, i.e., that might occur "naturally." For example, for a BCA of a utility electric vehicle program:

- The Reference Case should include all the electric vehicles on the road at the time of evaluation plus all the electric vehicles expected to occur naturally.
- The DER Case should include all the electric vehicles in the Reference Case plus the incremental electric vehicles expected to be adopted as a result of the utility initiative.

This is illustrated in Figure 2 below, where a hypothetical utility electric vehicle program starting in 2023 is presented in the DER Case and compared with a Reference Case. The BCA for this electric vehicle program should capture the difference between the two cases. A BCA that used a Reference Case that included no new electric vehicles after 2023 would significantly overstate the impact of the utility electric vehicle program.

Figure 2. Illustration of reference and DER cases: utility electric vehicles program



Regardless of the amount of DERs assumed in the Reference and the DER Cases, all the supply-side resources included in each case should ideally be optimized to reduce system costs, while meeting applicable reliability, dispatch or construction constraints. Otherwise, the comparison between the two cases could be misleading. For example, in a DER Case, centralized power plants should be dispatched

Example: California utilities use an Avoided Cost Calculator to determine the benefits associated with DERs. The Avoided Cost Calculator compares two scenarios that are prepared as part of the utilities' integrated resource plan (IRP) processes. The No DER scenario assumes that no new DERs are installed in the future (i.e., the Reference Case) and the other scenario includes the level of DERs assumed to be installed in the future (i.e., the DER Case). The difference between these two cases provides the avoided costs of the DERs. (See CPUC 2020, pages 4-5.)

Note: The California Avoided Cost Calculator is set up to be applicable to many types of DERs. Therefore, the outputs from the calculator will not necessarily be tailored to the exact profile of any one DER type.

economically in light of the new load patterns created by the DERs being evaluated. In addition, the resources that can be deferred or avoided by the DERs (generation, transmission, and distribution resources) should be deferred or avoided to reflect that impact of the proposed DERs.

There are some circumstances where it is unnecessary to prepare two separate cases. For example, if only wholesale market prices are used to determine electric energy or capacity impacts, the market prices themselves represent marginal impacts and therefore there is no need to take the difference between two cases to determine what is marginal, i.e., incremental to a Reference Case. In this case, it is nonetheless necessary to determine which DERs to include in the electricity system when forecasting the wholesale market prices because the electricity load will affect the energy and capacity wholesale market prices.

Example: The 2021 AESC Study uses a forecast of wholesale energy and capacity prices to determine electricity generation and capacity impacts, and therefore does not take a difference between two cases. This study does, however, create several market forecasts (i.e., counterfactual scenarios) to identify the marginal costs under different scenarios of DER development. Each counterfactual scenario excludes the DER type that is being evaluated. In this way, each counterfactual indicates what the wholesale prices (i.e., marginal costs) would be in the absence of the DERs being evaluated. (See AESC 2021, pages 69-70.)

2.7. Determine Marginal Impacts

Marginal impacts represent the changes that would occur to utility systems, host customers, and society if the proposed DERs were to be implemented. Marginal impacts are one of the core elements of any BCA and it is important that they be properly defined and calculated. This section describes the rationale for using marginal (versus average) impacts, and for using long-run (versus short-run) marginal impacts.

2.7.1. Marginal Versus Average Impacts

When conducting BCAs, marginal impacts are appropriate to use rather than average impacts. Marginal impacts are explicitly designed to capture the effects of adding DERs or other resources onto the electricity or gas system, such as the avoided cost of not having to produce an incremental unit of energy. Average impacts, on the other hand, blend the impacts of the DERs in with the costs of serving the rest of energy demand, and thus do not isolate the change in costs created by the DERs.

When conducting BCAs, marginal impacts are appropriate to use rather than average impacts.

Marginal and average impacts are defined as:

- *Average impacts* - the cost of producing a product divided by the number of products produced.
- *Marginal impacts* - the change in per-unit costs as the result of a small change in output.

For electric and gas utilities, average and marginal impacts are generally calculated as shown in Table 2.[3] In practice, however, many impacts are lumpy, rather than following a smooth, continuous function. Capacity costs, in particular, may be zero (or negative) when there is surplus capacity but then skyrocket

[3] This chart includes three example calculations, one for each of the three main metrics used in BCAs: $/MWh, $/kW-year, and $/MMBtu.

when there is a shortage. For this reason, marginal impacts are sometimes calculated over larger increments of output (e.g., 50 MW), and then presented as unit costs (e.g., $/kW).

Table 2. Calculating average and marginal impacts for electric and gas utilities

	Average impacts	Marginal impacts
Annual electric energy cost ($/MWh)	total variable energy costs (in $) / total energy production (in MWh)	change in the annual energy costs (in $) as the result of a small change in energy demand (e.g., one kWh)
Annual electric generating capacity cost ($/kW-year)	total generation capacity cost (in $) / total capacity provided (in kW-year)	change in annual capacity costs (in $) as the result of a small change in peak demand (e.g., one kW)
Annual gas production cost ($/MMBtu)	total gas cost (in $) / total annual gas production (in MMBtu)	change in annual gas costs (in $/MMBtu) as the result of a small change in gas demand (e.g., one MMBtu)

Both average and marginal impacts can be calculated for different time periods, e.g., hours, days, months, seasons, years.

2.7.2. Long-Run Versus Short-Run Marginal Impacts

When conducting BCAs, long-run marginal impacts are appropriate to use rather than short-run marginal impacts. This is necessary to ensure the analyses properly account for all benefits and costs experienced over the study period, which typically lasts 20 years or more. Using short-run marginal impacts will significantly understate the potential impacts of DERs.

When conducting BCAs, *long-run* marginal impacts are appropriate to use rather than *short-run* marginal impacts.

Short-run costs are defined as the costs that occur before capital investments are made to increase production capacity. For electric and gas utilities:

- Short-run marginal *electricity* costs include those costs, such as fuel, operations and maintenance (O&M), and labor costs, that are incurred to produce electricity without requiring additional investments in new generation, transmission, or distribution capacity.
- Short-run marginal *gas* costs included include those costs, such as fuel, O&M, and labor costs, that are incurred to produce gas without requiring additional investments in new capacity for production, transportation, or delivery of gas.

Long-run costs treat all costs as essentially variable, including capital costs. These include short-run costs as well as capital investments to increase production capacity. Long-run costs should include all costs incurred over the full BCA study period. For electric and gas utilities:

- Long-run marginal *electricity* costs include all short-run marginal impacts plus the costs associated with new generation, transmission, and distribution capacity investments. Long-run costs should also account for any reductions in capacity, such as the retirement of existing generation, transmission, and distribution facilities.

- Long-run marginal *gas* costs include all short-run marginal impacts plus the costs associated with new capacity for production, transportation, or delivery. Long-run costs should also account for any reductions in capacity, such as the retirement of existing production, transportation, and delivery facilities

In sum, short-run costs assume there are no new capital investments or new production capacity, whereas long-run costs assume new production capacity and include the costs associated with that new capacity. Therefore, it is important to use long-run marginal impacts in BCAs for DERs, because DERs can potentially postpone or avoid capacity costs that are not included in short-run costs.

2.7.3. Timing and Magnitude of Marginal Impacts

Marginal impacts are based on a change in the amount of electricity or gas production as a result of the proposed DER. The timing and magnitude of DER impacts can significantly affect the marginal cost. For example:

- A one MW change in demand during *a peak hour* of the year would result in higher marginal impacts than would a one MW change in demand during an *off-peak hour* of the year.
- A *one MW* change in demand for each hour of the year would result in different marginal impacts than would a *one GW* change for each hour of the year.

A DER Case should include a forecast of the magnitude of proposed DERs to be implemented in each year and should ideally account for the hourly load impact profile of the proposed DERs throughout each year (see Chapter 11). For example:

- For an efficiency program that reduces refrigeration demand consistently by 5 MW each hour of the year, the DER Case should reflect a 5 MW reduction in demand for each hour of the year, for each year when the efficiency measures operate.
- For a demand response program that reduces peak demand by 20 MW each month, the DER Case should reflect a 20 MW reduction in peak demand each month, for each year the program operates.
- For a distributed generation compensation mechanism that encourages residential distributed PV resources, the DER Case should reflect a reduction in demand for each hour the PV resources are expected to operate each day of the year, for each year the distributed PV resources operate.
- For a distributed storage program, the DER case should reflect the hourly increases and decreases in demand caused by the storage technology, for the years that the storage technology operates. For some storage resources that are expected to provide ancillary services or be used for sub-hourly energy arbitrage, it would be better to reflect sub-hourly changes in demand.
- For a building electrification program, the DER Case should reflect the hourly increased energy and peak demands caused by the new electric end-uses, for each year the installed technologies operate.
- For an electric vehicle charger installation program, the DER Case should reflect the projected hourly electric vehicle charging patterns, for each year the chargers operate. If the electric vehicles will be charging according to time-of-use rates, then the DER Case should assume electric vehicle charging patterns consistent with those rates.

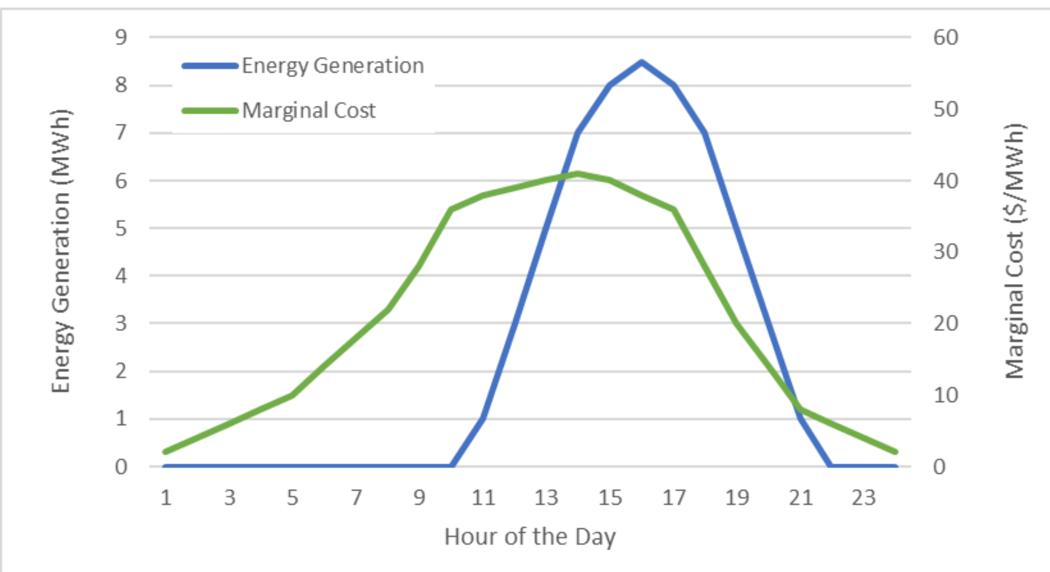
The exact approach used to calculate the marginal impacts on the utility system from the proposed DER might have relatively small implications when small amounts of DERs are expected to be installed, because small amounts of load reduction might not significantly change the marginal resources on the system. When large amounts of DERs are expected to be installed (relative to the total resources on the system), however, then the assumptions made about marginal changes to the system can have significant implications for the results of the BCA.

2.8. Calculate the Dollar Value of Marginal Impacts

The dollar value of an impact is determined by multiplying the relevant metric (e.g., MWh, kW, MMBtu, ton of pollutant) by the marginal cost (e.g., $/MWh, $/kW, $/MMBtu, $/ton of pollutant). The marginal impacts should be "mapped onto" the DER load impact profile, i.e., the marginal impacts should be based on the same time period when the DER is operating (hour, day, week, month, season, or year, depending upon the DER and data available).

Figure 3 illustrates how hourly marginal impacts should be mapped onto the hourly DER load impact profile. This example is for a distributed PV resource. The PV load impact profile is indicated by the blue line, while the marginal energy cost is indicated by the green line. Both the marginal cost and the energy generation vary throughout the day. In order to properly calculate the dollar value of the PV generation, the hourly marginal costs should ideally be multiplied by the hourly energy generation, for each hour of the day.

Figure 3. Illustration of mapping marginal impacts onto DER load impact profile



Note: Values are meant to be illustrative and do not represent an actual PV project or actual marginal costs.

2.9. Summary

A summary of the key steps to calculating BCA impacts is provided below. Many of these (or similar) steps are used in the methods described throughout this MTR handbook. (Note that the steps listed below are not exactly the same as those listed in Figure 1 because it is not necessary to go through all of those steps for each of the impacts.)

Table 3. Key steps to calculate BCA impacts of DERs

Step 1	Identify impact metrics: Once the relevant impacts for the BCA test are identified (see NSPM 2020), these impacts will define the relevant metrics to use in estimating the value of marginal impacts, e.g., MWh, kW, MMBtu, others. (See Section 2.2. and Table 4.)
Step 2	Determine DER load impact profiles: The DER load impact profiles can be used to estimate the energy and capacity impacts of the proposed DER, i.e., the magnitude and timing of MWh, kW, MMBtu, or other impacts. (See Section 2.5.)
Step 3	Develop the Reference Case: The Reference Case creates a baseline against which the DERs will be compared. (See Section 2.6.)
Step 4	Develop the DER Case: The DER Case should include all the incremental DERs being evaluated in the BCA and should not include all the other resources avoided by those DERs. (See Section 2.6.)
Step 5	Determine the marginal impact: The marginal impact can be calculated as the difference between the value of the relevant metric(s) for the DER Case minus the value of the relevant metric(s) for the Reference Case. (See Section 2.7.)
Step 6	Calculate the dollar value of the impacts: The dollar value is determined by multiplying the relevant metric by the marginal impact. The marginal impacts should be “mapped onto” the DER load impact profile. (See Section 2.8.)

Using the above steps, Table 4 provides examples for some key DER impacts.

Table 4. Overall structure for calculating the value of several DER impacts

Step	Calculation	Electric Energy	Electric Capacity	Gas Energy	Reliability
Identify Impact Metric(s)	Determine based upon type of impact	MWh	kW	MMBtu	SAIDI & SAIFI
Determine DER Load Impact Profiles	Determine based upon DER type and use case	MWh	kW	MMBtu	kW, MMBtu
Develop Reference Case	Calculate the magnitude and value of relevant metrics	$ and MWh	$ and kW	$ and MMBtu	$ and hours of outage time
Develop DER Case	Calculate the magnitude and value of relevant metrics	$ and MWh	$ and kW	$ and MMBtu	$ and hours of outage time
Determine Marginal Impact	Calculate the difference between DER and Reference Cases	$/MWh	$/kW	$/MMBtu	$/hour
Calculate Dollar Values	Map marginal impact onto load impact profile	$	$	$	$

For Step 5, the per-unit costs (in $/MWh, $/kW, $/MMBtu, and $/hour) are calculated by dividing the difference in cost (in $) by the difference in the metric (MWh, kW, MMBtu, or hour), where the differences are equal to the values from the DER Case (from Step 4) minus the values of the Reference Case (from Step 3).

Not all impacts/metrics need to be calculated using the above structure. In some cases, the marginal impact can be determined without a full analysis and comparison of a Reference and a DER Case. Table 5 provides some examples of simpler calculations for Other Fuel and GHG emission impacts, where existing data is used to calculate the marginal impact.

Table 5. Simpler structure for calculating the value of some impacts

Step	Calculation	Other Fuels (e.g., oil)	GHG Emissions
1. Define Relevant Metric(s)	Determine based upon type of impact	barrels	tons of GHG, MWh
2. Identify Load impact profiles	Determine based upon DER type and use case	barrels	MWh
3. Develop Reference Case	Calculate the magnitude and value of relevant metrics	not necessary	not necessary
4. Develop DER Case	Calculate the magnitude and value of relevant metrics	not necessary	not necessary
5. Calculate Marginal Impact	Difference between DER and Reference Cases	oil price represents the marginal impact ($/barrel)	use publicly available marginal GHG emission rates ($/MWh)
6. Calculate Dollar Value	Map marginal impact onto load impact profile	$	$

Some impacts can be calculated with methods that are even simpler than this. For example, DER program administration costs include only the incremental administration costs associated with the program. In this example, the metrics are in dollars, the load impact profile is not relevant, and there is no need to conduct a full-blown analysis of all the utility program costs in a Reference Case or the DER Case. All that is needed is an estimate of the incremental administration costs of the program.

3. Electric Utility System Impacts

3.1. Introduction

3.1.1. Applications

Electric utility system impacts are relevant in two BCA situations:

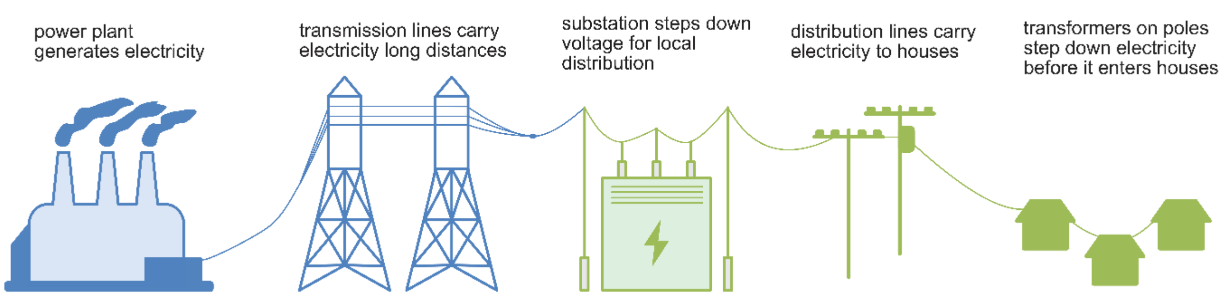
- When electric utilities implement or support DER programs that reduce or increase end-use electricity consumption.
- When gas utilities implement or support DERs that reduce or increase end-use electricity consumption.

This chapter addresses electric utility system impacts for both situations.

3.1.2. Overview of the Electric Utility System

The Figure 4 below demonstrates at a high level how electricity flows from the generation site to the end-use customer. Electricity starts at the generation station before moving through high-voltage transmissions lines. The transmission lines lead to a substation (or substations) that drop the power voltage. Finally, smaller distribution lines transfer the electricity to end-use customers.

Figure 4. Overview of the electric utility system



In many states, the electricity utilities are vertically integrated and provide all the generation, transmission, and distribution services depicted above. Other states have established wholesale competitive electricity markets, where the generation services are provided by unregulated independent power producers while the transmission and distribution services are provided by the regulated utilities. Other states have a hybrid of these two models, where the regulated utilities are vertically integrated, but they buy and sell electricity into competitive wholesale markets. This chapter addresses all types of utility structures.

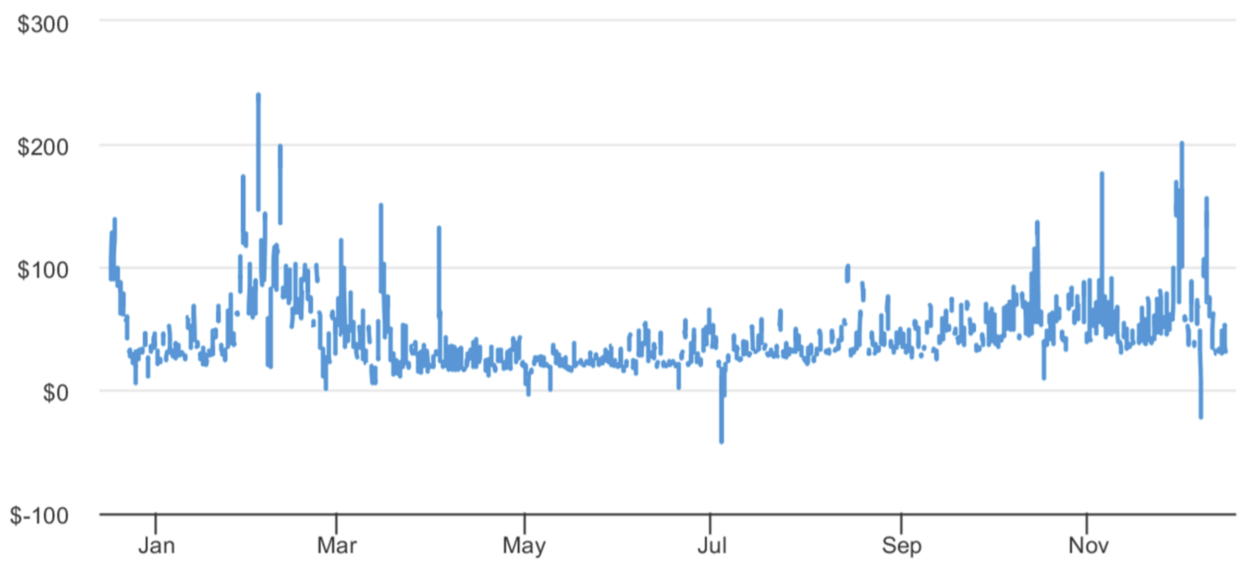
3.2. Generation Impacts

3.2.1. Energy Generation

3.2.1.a. Definition

Energy generation costs consist of the fuel and variable O&M costs from the production or procurement of energy (i.e., kWh) from generation resources. Energy generation costs can vary significantly by season and time of day. Figure 5 presents the variability of locational marginal energy prices in ISO New England throughout a year, tracked in real time throughout 2021.

Figure 5. Daily locational marginal price at New England Hub ($/MWh)



Source: U.S. Energy Information Administration. 2021. "New England Dashboard." (Accessed 12/17/2021). Available at: www.eia.gov/dashboard/newengland/electricity.

In general, DERs will (a) create energy generation benefits when they reduce the amount of electricity utilities need to produce or procure in order to meet load, or (b) create energy generation costs if they require higher levels of energy generation. An exception to this occurs during periods of negative pricing whereby consuming grid energy (e.g., storage or electric vehicle charging) results in a benefit and curtailing grid energy consumption results in a cost.

3.2.1.b. Methods for Calculating Energy Generation Impacts

Figure 6 summarizes the common methods for estimating energy generation impacts, each of which is described in detail below. Section 3.2.1.c further summarizes the advantages and disadvantages of each method (see Table 12).

Figure 6. Common methods for estimating energy generation impacts

Proxy Unit Method	Power Sector Modeling	Market Data Method	Public and Proprietary Forecasts
• Determine energy saved or generated using DER load impact profile • Identify proxy unit(s) to be avoided • Identify proxy unit operating costs to determine avoided energy costs • Escalate costs over study period	• Develop Reference Case forecast for meeting load • Run capacity expansion model to determine future resource build-out • Simulate dispatch of resources using production cost model to determine energy prices for single year • Extend production cost modeling over BCA study period	• Determine energy saved or generated using DER load impact profile • Obtain historical LMPs from system operator website • Calculate avoided energy costs by weighting LMPs by the load impact profile of the DER or DER portfolio • Escalate avoided energy costs over study period	• Use publicly available historical energy cost data as benchmark • Use publicly available forecasts as inputs • Obtain propietary energy generation impact forecasts to use as inputs, if possible

Option 1: Proxy Unit Method

The proxy unit method calculates the energy generation impacts associated with a hypothetical generation unit that would be avoidable by the procurement of DERs (see EPA 2018; NREL 2014 DPV). The proxy unit should represent the generation resource likely to be on the margin during the time of day a DER impact would occur.

This method is one of the more simplistic approaches to calculating avoided energy generation costs. It involves the key steps shown in Table 6.

Table 6. Steps for using the proxy unit method for determining energy generation impacts

Step 1	**Determine the energy saved or generated by the proposed DER** This can be determined using the proposed DERs' load impact profiles (see Chapter 11). Ideally, the savings or generation would be developed on an hourly basis, to reflect the variation across different time periods.
Step 2	**Identify the proxy unit that will be avoided by the DERs** Use the load impact profile of the DERs from Step 1 to establish which generation unit is likely to be on the margin at the time of DER operation and should therefore serve as the proxy unit. For example, energy efficiency is more likely to impact baseload generation on a system, indicating that the marginal unit would likely be a coal plant or natural gas combined cycle plant. Whereas storage is typically operated on-peak and will impact peaking resources like a natural gas combustion turbine plant. If the portfolio of DERs has a wide range of load impact profiles, more than one proxy unit may be identified. In this situation, a weighted proxy unit can be calculated based on weighting multiple proxy units by the DER load impact profiles.
Step 3	**Identify the operating costs of the proxy unit** This will include fuel costs (e.g., natural gas or oil), variable O&M costs (i.e., costs that are a function of energy generation), and marginal emissions costs that are embedded in the cost of generation. The operating costs of the proxy unit will serve as the energy generation impacts of the DER.

The calculation for avoided energy generation costs using the Proxy Unit Method is:

$$Avoided\ Energy\ Cost\ \frac{\$}{kWh} = Proxy\ Unit\ Heat\ Rate\ \frac{BTU}{kWh} * Cost\ of\ Fuel\ \frac{\$}{BTU} + Other\ Variable\ Costs\frac{\$}{kwh}$$

Step 4 Escalate avoided energy costs from Step 3 over the study period

The fuel cost portion can be escalated using fuel price forecasts. The other variable costs can be escalated using real escalation factors associated with electricity and gas costs.

The primary advantages of this method include its simplicity and use of generic, public data. The primary disadvantages include its potential inaccuracy if the selected proxy unit does not accurately reflect the operating characteristics of the DERs. Further, it does not capture the potential impacts to baseload units, and it does not account for future changes to the electric system that may lead to changes in the marginal unit.

Key Data Sources for Proxy Unit Method

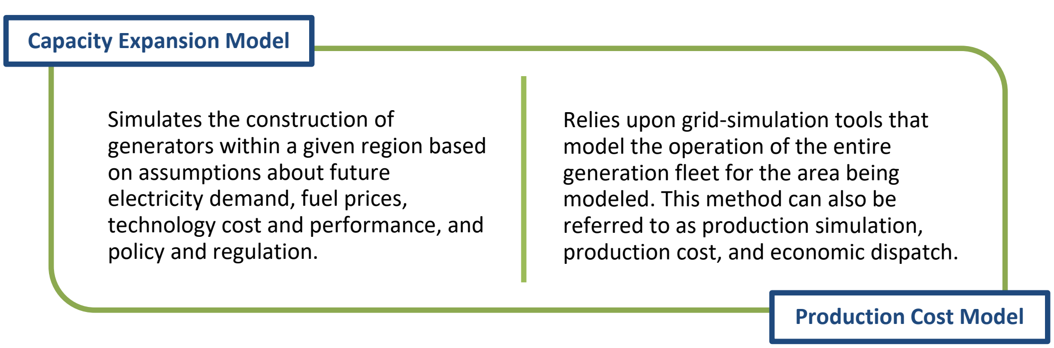
Data for determining operating costs for the proxy unit is available from the following sources.

- Electricity and natural gas price forecasts
  - U.S. EIA's *Annual Energy Outlook.* (See U.S. EIA AEO 2022.)
  - New York Mercantile Exchange gas futures. (See CME Group, Henry Hub.)
  - Horizons Energy's National Database. (See Horizons Energy, n.d.)
- NREL's annual technology baseline has heat rates and projected variable O&M costs for various types of electrical generators. (See NREL ATB.)
- Marginal fuel mix can often be found on ISO and RTO websites. (See PJM Fuel Data.)

Option 2: Power Sector Modeling Method

Power sector modeling tools are a detailed and complex approach to calculating energy generation impacts. The most common tools are the capacity expansion model and the production cost model, described in Figure 7 below.

Figure 7. Summary description of capacity expansion and production cost models



A production cost model typically provides for higher temporal resolution (i.e., hours to minutes) than the capacity expansion model. However, a production cost model will only report short-run impacts, unless it is paired with a capacity expansion model. Therefore, the production cost model is typically used in combination with a capacity expansion model to develop long-run avoided energy generation costs.

The use of the capacity expansion with the production cost model for developing energy generation impacts typically involves the steps in Table 7.

Table 7. Steps for developing energy generation impacts with capacity expansion and production cost modeling

Step 1	Develop a Reference Case forecast for how load will be met This forecast should include the customer load expected over the study period but should not include the load impacts of the DERs being evaluated in the BCA (see Section 2.5). This involves entering the following inputs into the model: the projected growth in electricity demand, changes in energy and fuel prices, existing fleet of generating assets, operating characteristics of potential new generating units, and environmental regulations (current and planned). The capacity expansion model uses these inputs to determine a future business-as-usual build-out of the system through an optimization process that chooses the least-cost solution to adding capacity.
Step 2	Run the capacity expansion model This process will determine the future resource build-out on the system.
Step 3	Run the production cost model Using the resource build-out from Step 2, the production cost model should be run to simulate the dispatch of those resources. The model will determine the least-cost mix of generators needed to meet load during a given time interval, typically one year in 8,760-hour increments. The production cost model will output the avoided energy cost in the form of energy prices.
Step 4	Forecast energy costs over the BCA study period Production cost models typically provide one-years' worth of energy costs. Calculating energy costs over the BCA study period requires running a production cost model for multiple years to capture the changing generator mix over time, based on the results of the capacity expansion model. For practical purposes, the production cost model runs can be limited, for example by running it for the first 10 years and extrapolating beyond that, or by running it in five-year intervals and interpolating between them.

(See U.S. DOE Gateway; NREL 2014 DPV.)

Table 8 below provides information on a range of capacity expansion and production cost models available for analyzing energy generation impacts.

Table 8. Examples of capacity expansion and production cost models to estimate energy generation impacts

Category	Subcategory	Model	Link
Capacity Expansion Models	National-Scale Models	Integrated Planning Model (IPM)®	www.icf.com/resources/solutions-and-apps/ipm
		U.S. DOE's National Energy Modeling System (NEMS)	www.eia.gov/outlooks/aeo/info_nems_archive.php
		NREL's Regional Energy Deployment System model (ReEDS)	www.nrel.gov/analysis/reeds/
		MARKAL (MARKetAllocation)	iea-etsap.org/index.php/etsap-tools/model-generators/markal
		Haiku	www.rff.org/documents/506/RFF-RPT-haiku.pdf
		ENERGY 2020	www.energy2020.com/
		The WIS:dom® Planning Model	www.vibrantcleanenergy.com/products/wisdom-p/
	Utility-Scale Models	NREL's Resource Planning Model (RPM):	www.nrel.gov/analysis/models-rpm.html
		AURORA	epis.com/aurora/
		Electric Generation Expansion Analysis System (EGEAS)	eea.epri.com/models.html#tab=3
		PLEXOS*	energyexemplar.com/solutions/plexos/
		e7 Capacity Expansion	new.abb.com/enterprise-software/energy-portfolio-management/commercial-energy-operations/capacity-expansion
		e7 Portfolio Optimization	new.abb.com/enterprise-software/energy-portfolio-management/commercial-energy-operations/portfolio-optimization
		RESOLVE: Renewable Energy Solutions Model	www.ethree.com/tools/resolve-renewable-energy-solutions-model/
		EnCompass*	anchor-power.com/encompass-power-planning-software/
Production Cost Models		PROMOD	www.hitachienergy.com/offering/product-and-system/energy-planning-trading/market-analysis/promod
		GE-Maps	www.geenergyconsulting.com/practice-area/software-products/maps
		GridView	www.hitachienergy.com/offering/product-and-system/energy-planning-trading/market-analysis/gridview

*Note: *Model can be used in Production Cost and Capacity Expansion mode. The utility-scale models often have higher spatial and temporal resolution and are often used for IRPs (See U.S. DOE Gateway).*

Key Data Sources for Power Sector Models

The capacity expansion and production cost models require significant data collection. This includes fuel price forecasts, load forecasts, transmission constraints, electricity generator cost and performance assumptions for both existing and potential new plants, DER cost and performance assumptions (including load impact profile), and state and federal environmental regulations and requirements (see NREL 2014 RPS.)

To populate the needed inputs, databases for models are available for purchase but require technical expertise. In some models, default data may be included, but modifying this data to fit the needs of the analysis may require technical expertise.

Some models calibrate historical or projected results against other existing datasets, such as the NEMS-generated *Annual Energy Outlook* produced by U.S. EIA, or historical data published by U.S. EIA or independent system operators. In other cases, this calibration is left up to the user to do on their own.

Data for individual power plants is available from public sources:

- Capacity and average heat rate data:
  - FERC forms 1 and 714
  - U.S. EIA 2020
- Part-load heat rate data must be obtained from the operator or by reconstructing them via U.S. Environmental Protection Agency (EPA) historical continuous emissions monitoring system (CEMS) datasets. (See NREL 2014 RPS.)

Table 9 provides multiple examples of how states use power sector models to analyze energy generation impacts.

Table 9. State examples using the power sector model method to estimate energy generation impacts

State	Summary
New England states	2021 AESC projects New England electric system energy levels and prices from 2021 to 2035 using the EnCompass model (in both capacity expansion and production cost mode). The wholesale energy prices produced by the model change over time (and on a peak and off-peak basis) depending on the system demand, available units, transmission constraints, fuel prices, and other attributes. (See AESC 2021.)
California	California Public Utilities Commission (CPUC) uses SERVM, “a production simulation model that represents a theorized and optimized view of the day-ahead market” to develop avoided energy costs for DERs. SERVM generates wholesale electricity prices based on the input system load and dispatch of the modeled generation portfolio. (See CPUC 2020.)
Georgia	Southern Company uses an hourly production cost model to develop its avoided energy costs. The model uses scenario-specific information including fuel price forecasts, fleet expansion plans, and emissions allowance prices. The model also includes inputs related to unit characteristic like heat rates, emission rates, and variable O&M, as well as transmission constraints, and economic energy purchases and sales. (See Southern Company 2017.)
South Carolina	The marginal value of energy derived from production simulation runs per the utility's most recent IRP study and/or Public Utility Regulatory Policy Act (PURPA) Avoided Cost formulation. (See E3 2015.)
North Dakota	Black Hills used a production cost model to determine the hourly costs of serving its system load of a 20-year contract for a Qualifying Facility (QF). The production cost model forecasts the hourly dispatch of the dispatchable resources based on how the marginal production cost of each resource compares to the market price in each hour. (See White 2019.)

Option 3: Market Data Method

In restructured markets, avoided energy generation impacts can be based on wholesale market prices. These prices are based on what generators bid into the market and represent the actual costs for operating marginal units. This is a relatively simplistic method that only requires the use of a spreadsheet to calculate energy generation impacts.

Within these markets, it is common to use the Locational Marginal Price (LMP) that can be obtained for specific points (nodes) on the system. LMPs can also be obtained for on-peak and off-peak periods, hourly, and in some cases for five-minute intervals. Depending upon the Independent System Operator (ISO), LMPs can include energy costs, capacity costs, and transmission congestion costs. Therefore, it is important to ensure that the energy generation impacts are not double-counting capacity or transmission impacts.

Calculating energy generation impacts using this method involves the four key steps shown in Table 10.

Table 10. Steps for calculating energy generation impacts using the market data method

Step 1	Determine the energy saved or generated by the proposed DER This can be determined using the proposed DERs' load impact profiles (see Chapter 11). Ideally, the savings or generation would be developed on an hourly basis, to reflect the variation across different time periods.
Step 2	Obtain historical LMPs from the system operator's website This information is available to the public. Depending on the age of the data it may need to be adjusted for inflation.
Step 3	Calculate the avoided energy cost Weight the LMPs by the load impact profile of the DER or DER portfolio.
Step 4	Escalate avoided energy costs from Step 3 over the study period Some markets like NYISO provide annual and hourly forecasts of LMP for 20 years. However, other markets like MISO, PJM, and ISO-NE do not provide public forecasts. In these cases, prices can be escalated using forecasts from publicly available sources. (See U.S. EIA AEO 2022.)

(See RAP 2013; ConEdison 2020; NREL 2014 RPS; Clean Power Research 2015.)

Key Data Sources for Market Data Method

The following sources provide useful information for escalating energy costs:

- U.S. EIA's *Annual Energy Outlook.* (See U.S. EIA AEO 2022.)
- New York Mercantile Exchange (NYMEX) gas futures is applicable for systems that are driven by natural gas generation resources (e.g., ISO-NE, PJM). (See CME Group, Henry Hub.)
- Horizons Energy's National Database. (See Horizons Energy, n.d.)
- Market and system operator hourly marginal costs. (See FERC Form 714.)

For examples of states using the market data method to estimate energy generation impacts, see Table 11 below.

Table 11. State examples using the market data method to estimate energy generation impacts

State	Summary
Arkansas	Uses MISO LMPs weighted by a standard output of a DER then escalated using the long-term forecast of natural gas prices from U.S. EIA's *Annual Energy Outlook* at the Henry Hub. (See Crossborder Energy 2017.)
New York	NYISO provides annual and hourly locational-based marginal price (LBMP) forecasts for 20 years by zone for bulk system, which accounts for energy, congestion, and losses. Hourly LBMP is then applied to the energy associated with the DER load impact profile, adjusted for losses. (See ConEdison 2020.)
Washington D.C.	For solar, uses LMPs (minus congestion and marginal loss costs) for the PEPCO zone of PJM. The total avoided energy benefit across each year is calculated by correlating each hour's generation in PVWatts to a system marginal energy cost, based on historical data for the PJM Interconnect. For future years, U.S. EIA's *Annual Energy Outlook* Reference Case was used to scale up the base-year weighted energy cost, based on generation prices in the relevant PJM region. (See Synapse 2017.)
New Jersey	Calculated using the three-year rolling average of historical PJM wholesale prices multiplied by the quantity of electricity not consumed. (See NJ BPU 2020.)

Option 4: Publicly Available Energy Generation Impacts

It is sometimes possible to use energy generation impacts provided by publicly available sources, instead of the methods described above. For example, when regional studies are prepared for multiple states or when the available forecasts are suitable for the level of detail needed for the DER BCA. The following is a list of publicly available data sources.

Historical Information

Historical energy cost data cannot be directly used as inputs for forward-looking BCAs. Nonetheless, historical energy cost data might be helpful as a starting point for developing forecasts or as a benchmark against which to evaluate forecasts.

- Hourly marginal energy costs. (See FERC Form 714.)
- DOE's State and Local Energy Data (SLED) provides basic energy market information including electricity generation, fuel sources and costs, applicable policies, regulations, and financial incentives. (See OpenEI State and Local.)
- National Electric Energy Data System (NEEDS) is the database of existing and planned-committed generating units used to construct the "model" plants in U.S. EPA's current base case of the IPM Model. It specifies plant characteristics including capacity, heat rate, and emissions rates. (See U.S. EPA NEEDS.)
- System lambdas: for jurisdictions with vertically integrated utilities, system lambdas can be used. The system lambda represents the marginal cost of electricity in a system (i.e., the marginal cost of the marginal unit). This approach may underestimate costs due to the fact it does not account for marginal transmission losses, congestion costs, or scarcity prices during constrained hours. (See FERC Form 714.)

Forecasts

- *Avoided Energy Supply Components in New England: 2021 Report* provides avoided energy generation impacts for the six New England States. (See AESC 2021.)

- California Avoided Cost Calculator provides avoided energy generation impacts for DERs deployed in the state of California. (See CPUC 2020 Avoided Costs; E3 EE.)
- Northwest Power and Conservation Council (NPCC) for Idaho, Montana, Oregon, and Washington provides a wholesale electricity price forecast and its Production Cost Simulation results. (See NPCC Forecast; NOCC Production Cost Simulation).

Option 5: Proprietary Energy Generation Impact Forecasts

Utility forecasts are often proprietary. Typically, the only way for non-utility stakeholders to obtain proprietary forecasts is through a docketed case where discovery is permitted.

There are also for-profit companies that develop and provide forecasts for a fee. Examples include, Wood Mackenzie, HIS Global, and Bentek.

3.2.1.c. Choosing a Method to Calculate Energy Generation Impacts

Table 12 provides a summary of common methods for estimating avoided energy generation impacts with a brief description of the method, its advantages, and disadvantages.

Table 12. Advantages and disadvantages of common methods to calculate energy generation impacts

Method	Description	Advantages	Disadvantages
Proxy Unit	Calculates the energy generation impacts associated with a hypothetical generation unit that would be avoidable by the procurement of DERs	Simple approach; information available to those outside of utility; does not require detailed data or modeling; inexpensive	May produce inaccurate costs; may not apply to DERS with vastly different load impact profiles; does not reflect displacement of baseload units or changes to system over time; may miss interactive effects
Power Sector Modeling	Capacity Expansion model and Production Cost model	Provides granular pricing (hourly and sub-hourly); high level of accuracy due to ability to capture complex interactions, variable costs, and generation dispatch characteristics	Requires technical expertise and is labor intensive and expensive; lack of transparency and information asymmetry between utilities and stakeholders
Market Data	Uses wholesale electricity prices, which reflect the actual costs for operating marginal units in the bids that generators submit; uses system lambdas for vertically integrated utilities	Relatively simple approach; captures regional variation; based on local generation mix; includes transmission congestion	Potential to double-count impacts with other avoided costs; susceptible to weather misalignment
Public and Proprietary Forecasts	Use publicly available historical energy cost data as benchmark for making forecasts; use publicly available or proprietary forecasts as inputs	Simple approach; information available to those outside of utility; does not require detailed data or modeling; inexpensive	May not be as granular as desired; may not be as accurate or as up-to-date as other methods; proprietary forecasts might be expensive or unavailable to some stakeholders

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3.2.2. Generation Capacity

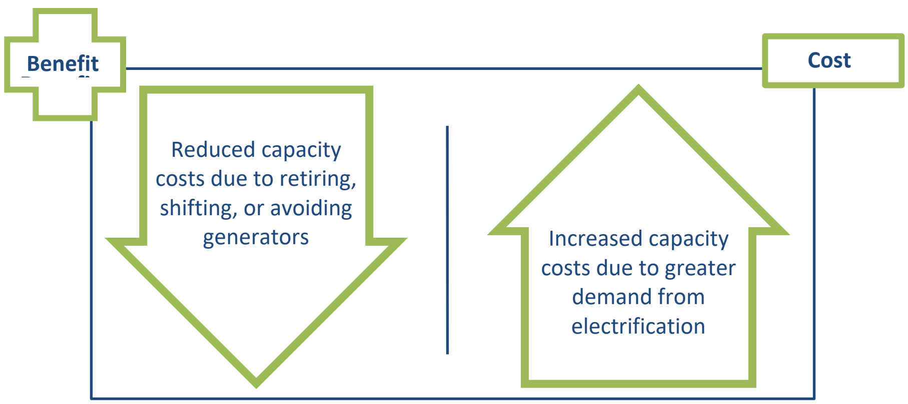
3.2.2.a. Definition of Generation Capacity Impacts

Generation capacity is the amount of installed capacity (i.e., kW) required to meet the forecasted peak load, which typically includes an additional reserve margin. A utility will either need to build generation capacity or procure it (for instance through bilateral contracts or wholesale market purchases) to ensure it has sufficient generation capacity to meet its planning requirement.

If a DER results in a net decrease in load (e.g., from energy efficiency savings, curtailment through demand response, PV generation, injections from storage) during the system peak, the utility will experience benefits in the form of lower generation capacity needs.

Consequently, DERs can impact generation capacity by inducing the retirement of generators and marginally changing the mixture of generators that would have otherwise been built. Alternatively, if a DER results in a net increase in load (such as with electrification) during the system peak, the utility will incur additional generation capacity costs. Figure 8 illustrates that DERs can impact generation capacity as either a benefit or a cost.

Figure 8. Depiction of benefit/cost factors



3.2.2.b. Methods for Calculating Generation Capacity Impacts

The methods used to determine energy generation values can also be used to determine generation capacity values. This section provides an overview of the common methods, with references to Section 3.1 where relevant. These methods can be used to calculate energy and capacity values separately, or they can be used to calculate energy and capacity values simultaneously. Either way, the estimates of energy and capacity values should be done with consistent inputs and assumptions. For example, the estimates of energy values should assume the same capacity additions that are used in the estimates of capacity values.

Figure 9 below summarizes the most common methods for quantifying or informing generation capacity impacts, each of which is described in detail below. Section 3.2.2.c further summarizes the advantages and disadvantages of each method (see Table 21).

Figure 9. Common methods for quantifying generation capacity impacts

Proxy Unit Method	Peaker Plant Method	Market Data Method	Power Sector Modeling	Public and Proprietary Forecasts
• Determine capacity saved/created by proposed DER • Identify most likely proxy unit • Determine long-term capital and fixed O&M	• Determine capacity resource on the margin • Determine per-unit fixed costs of the resource • Escalate fixed costs over study period	• Use market auction results to determine capacity prices through recent auction year • Determine capacity price forecasts for future years by calculating ratio of auction results to net cost of new entry	• Method 1: Estimate cost of new entry for marginal units by comparing Reference Case forecast to DER Case forecast • Method 2: Perform capacity market simulation by modeling resource build-out and dispatch to find avoided capacity costs	• Use publicly available historical energy cost data as benchmark • Use publicly available forecasts as inputs • Obtain propietary generation capacity impact forecasts to use as inputs, if possible

Option 1: Proxy Unit Method

The proxy unit method for calculating generation capacity impacts is similar to that used for avoided energy generation as described in Section 3.2.1.b. The proxy unit method uses a hypothetical generation unit that serves as a proxy to represent the next planned generating unit that is avoided or built due to the deployment of DERs. The proxy unit's capital and fixed O&M costs set the avoided capacity cost. This method is one of the more simplistic approaches to calculating avoided generation capacity.

The same three steps used to determine energy generation values can be used to determine generation capacity values.

Step 1 Determine the energy saved or generated by the proposed DER

This can be determined using the proposed DERs' load impact profiles (see Chapter 11). Ideally, the savings or generation would be developed on an hourly basis to reflect the variation across different time periods.

Step 2 Identify the proxy unit that is most likely to be avoided or built due to those DERs

The proxy unit can be identified as the next planned generating unit in a utility's IRP. In the absence of an IRP, proxies can be based on the most likely resource to be installed next to meet capacity needs. Typically, this is a natural gas combustion turbine (NGCT). However, NGCT's might no longer represent the marginal capacity resource in some states or regions. For example, to better align with the latest IRP modeling results, California's 2020 Avoided Cost Calculator recently switched from using a NGCT to a 4-hour storage battery storage resource as the marginal generating unit for determining new-build avoided generation capacity costs (see CPUC 2020).

Step 3 Determine the long-term capital and fixed O&M costs of the proxy unit

This is typically the cost of building a new power plant, less the value of the energy generated by that resource. This requires conducting a discounted cash flow analysis that includes initial construction costs, fixed operating costs, and financial data, including carrying costs (see U.S. EPA 2018). The resulting costs are then annualized over the expected life of the proxy unit to yield an annual capacity cost per kW.

The equation for calculating annual avoided capital cost is:

$$Annualized\ Costs\left(\frac{\$}{kW\ Year}\right) * Annual\ Capacity\ Savings\ (kW) = Avoided\ Capital\ Costs\left(\frac{\$}{Year}\right)$$

(See UCS 2020 MN; EPA 2018.)

The primary advantages and disadvantages of this method are essentially the same as those for estimating energy generation values. (See Section 3.2.1.b.)

Key Data Sources for Proxy Unit Method

There are several types of data required for the proxy unit method for estimating generation capacity impacts. (See U.S. EPA 2018.)

- Cost and performance of the proxy unit
    - NREL's Jobs and Economic Development Impact (JEDI) model is a free tool designed to allow users to calculate the economic costs and impacts of constructing and operating power generation assets. The tool provides plant construction costs, as well as fixed and variable operating costs. (See NREL JEDI.)
    - U.S. EIA's *Annual Energy Outlook* Electricity Market Module Chapter contains cost and performance characteristics of new generating technologies. (See U.S. EIA AEO 2022.)
    - Lazard Levelized Cost of Energy Analysis provides capital costs and levelized cost of energy for a variety of generation assets. (See Lazard 2020.)
- Capital cost escalation rates, discount rate, and other relevant financial data
    - Handy Whitman Index: A proprietary index that can be used to escalate capital costs. (See Handy Whitman 2022.)

The states of Hawaii and Colorado demonstrate use of the proxy unit method to estimate generation capacity impacts, as shown in Table 13.

Table 13. State examples using the proxy unit method to estimate generation capacity impacts

State	Summary
Hawaii	The long-term value of capacity represents the cost of building a new CT or CCGT, less the value of the energy generated by the new resource. The total annualized fixed cost of a new capacity resource is calculated using a pro forma model. (See E3 2014.)
Colorado	When the Public Service system showed an incremental capacity need, avoided capacity costs were based on the economic carrying charge (ECC) representation of a generic, combustion turbine's capital and fixed O&M costs. The resulting $/kw-month were escalated over time at an assumption for inflation and were assigned to distributed solar generation for all 12 months of each year. (See Xcel 2013.)

Option 2: Peaker Plant Method

This method calculates generation capacity costs "according to the annualized costs of a pure peaking generation plant" (see Christensen Associates 2014). The peaker plant should represent the resource most commonly used to meet peak demand on the system. This method differs from the proxy unit method in that it is not based on the cost of the next planned generating unit; it assumes that DERs reduce the marginal generation resource.

The peaker plant method involves the three key steps shown in Table 14.

Table 14. Steps to calculate generation capacity impacts using the peaker plant method

Step 1	Determine the capacity resource on the margin within the electric system
Step 2	Determine the per-unit fixed costs of that marginal resource The capacity-related portion of the peaker plant's fixed costs is assumed to represent the avoided cost of generation capacity. These should not include fuel or O&M savings.
Step 3	Escalate the fixed costs over the study period Use an index such as The Handy-Whitman Index, an annual industry-recognized construction cost index.

The primary advantages of this method are its simplicity and its reliance on information that can be obtained from public sources. The primary disadvantages are that it may not accurately represent the timing of the capacity need and the actual type of capacity available to the utility.

Key Data Sources for Peaker Plant Method

The data sources listed above for proxy unit method can also be used for the peaker plant method. Table 15 provides examples of states' use of the peaker plant method to estimate generation capacity impacts.

Table 15. State examples using the peaker plant method to estimate generation capacity impacts

State	Summary
South Carolina	Uses a peaker method to forecast avoided energy and capacity costs from Qualifying Facilities. Duke Energy applies peaker cost assumptions published by U.S. EIA for the cost of the avoided combustion turbine unit used to quantify the projected capacity value. (See SC PSC, Docket Nos. 2019-185-E and DOCKET NO. 2019-186-E.)
Georgia	Capacity costs for Qualifying Facilities are based on a Proxy Peaker Methodology. (See GPSC 2021.)

Option 3: Market Data Method

In restructured states with wholesale capacity markets, generation capacity impacts can be determined by market prices. There are two key sources of data available in these markets that can be used to calculate generation capacity impacts: capacity market clearing prices, and net cost of new entry (Net CONE).

- Wholesale Capacity Markets: There are three wholesale capacity markets in the United States: ISO-New England Forward Capacity Market (FCM), New York-ISO Installed Capacity Market (ICAP), and PJM Reliability Pricing Model (RPM). These auctions seek to procure sufficient generation capacity to meet projected load three years in advance.
- Net CONE: An estimate of capacity revenue needed by a new generator in its first year of operation to make it economically viable to build a power plant within a specific market. This value is net of any energy or ancillary services revenues and therefore is a suitable proxy for the value of avoided generation capacity.

While the market data method is a relatively simplistic method and based on publicly available data, the year-to-year variation in market prices can make it difficult to forecast capacity prices over the long term. A recent value of solar study in Washington D.C. provides an example of how capacity auction data can be combined with Net CONE values to increase the accuracy of long-term generation capacity forecasts (see Synapse 2017). This study involved the two key steps shown in Table 16.

Table 16. Steps used to calculate generation capacity impacts using market data and Net CONE values

Step 1	Determine capacity prices for 2019/2020 Used PJM Reliability Pricing Model (RPM) auction results for the PEPCO zone to through the 2019/2020 auction year.
Step 2	Forecast capacity prices beyond 2019/2020 Calculated a ratio of RPM auction results to Net CONE to account for observed historical variation in transmission constraints, auction price variability, and difference between PEPCO's Net CONE compared to the PJM-wide Net CONE. To calculate the ratio, the study used the most recent five-year Net CONE average (adjusted for inflation) as a forecast for both for PEPCO and PJM-wide Net CONE. The study then calculated the historical ratio of RPM results to Net CONE and multiplied that fraction by the forecasted Net CONE to calculate a forecast of capacity value through 2040.

The primary advantages of the market data method are that it is low cost, does not rely on models, and can be conducted with publicly available data. The primary disadvantages include that is may not adequately isolate the interaction of energy prices and capacity prices, it is limited to states served by a wholesale capacity market, and historical wholesale capacity auction clearing prices may not be a good indicator of long-term trends.

Key Data Sources Market Data Method

Wholesale capacity markets websites:

- ISO-NE Forward Capacity Market. (See NE-ISO FCM.).
- PJM Reliability Pricing Model. (See PJM RPM.)
- NY-ISO Installed Capacity Market. (See NY-ISO ICAP.)

Net CONE information:

- PJM: Cost of New Entry Reports. (See PJM CONE.)
- ISO-NE: FCM Parameters Section of the following website includes CONE values. (See NE-ISO FCM.)
- MISO: MISO has published a CONE estimate associated with its current 2018-2019 Planning Resource Auction. (See MISO PRAR.)

For examples of states using the market data method to estimate generation capacity impacts, see Table 17 below.

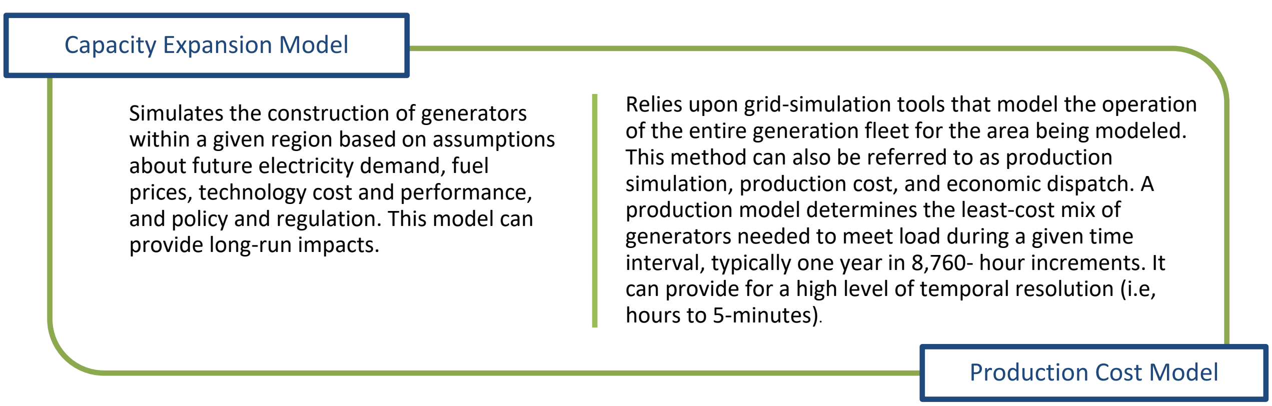
Table 17. State examples using the market data method to estimate generation capacity impacts

State	Summary
New England States	AESC 2021 develops avoided capacity prices for annual commitment periods starting in June 2020. The avoided capacity costs are driven by actual and forecasted clearing prices in ISO-NE FCM. AESC 2021 develops avoided capacity prices from the FCM auction prices using the actual results in auctions for delivery years 2021/22 through 2024/25 and calculating the historical results for the rest of the analysis period. The historical capacity prices are determined by matching the supply and demand curves for Forward Capacity Auction (FCA) 12 through FCA 15. The AESC 2021 forecast prices are based on observations made in recent auctions as well as expected future changes in demand, supply, and market rules. (See AESC 2021.)
Maine	For a value of solar study, generation capacity costs were based on ISO-NE Forward Capacity Market (FCM) clearing prices for the years 2014 to 2018. Due to changes in market rules, forecasts of future prices could not be based on historical results and relied on a simulated forecast based on data published in the 2014 IRP for Connecticut, annualized and adjusted for inflation. Capacity cost forecasts after 10 years were increased by a general escalation rate. (See Clean Power Research 2015.)
New York	The NY Department of Public Service (DPS) Staff provide Avoided Generation Capacity Costs (AGCCs) at the bulk system based on forecast of capacity prices for the wholesale market. This data is found in the ICAP Spreadsheet Model filed under Case 14-M-0101. The ICAP Spreadsheet converts "Generator ICAP Prices" to "Avoided CGG at Transmission Level" based on capacity obligations for the wholesale market and provides outputs in \$/kW-month. The utilities then convert this into \$/MW-year in order to match peak load impacts and calculate avoided generation capacity costs. (See ConEdison 2020.)
New Jersey	The NJ Cost Test offers two approaches for calculating avoided generation capacity: (1) revenues earned from the PJM capacity market (RPM) associated with offering and clearing energy efficiency into the RPM; or (2) for customers no monetizing capacity into the RPM, avoided capacity equals the difference in capacity costs for the pre-energy efficiency measure baseline minus load after the energy efficiency. (See NJ BPU 2020.)

Option 4: Power Sector Modeling Method

The modeling tools discussed in Section 3.2.1.b can also provide generation capacity values. The two types of models commonly used to develop generation capacity impacts are the capacity expansion model and the production cost model. Figure 10 briefly describes those models.

Figure 10. Summary of capacity expansion and production cost models



The choice of model will depend on numerous factors including whether the utility is vertically integrated or part of a capacity market, the needed level of granularity, and the study period.

Depending on these factors there are two methods that are available for estimating avoided capacity. It is important to note that not all capacity expansion and production cost models require the same steps. The methods described below are intended to be generic and may not apply to all models.

Method 1: Estimating Cost of New Entry for marginal units

This method, shown in Table 18, is typically used when deriving avoided generation capacity costs for vertically integrated utilities and can be used if the model does not simulate capacity markets.

Table 18. Steps for estimating Cost of New Entry for marginal units

Step 1	Develop a Reference Case forecast for how load will be met This forecast should include the customer load expected over the study period but should not include the load impacts of the DERs being evaluated in the BCA (see Section 2.5). This involves entering the following inputs into the model: the projected growth in electricity demand, changes in energy and fuel prices, existing fleet of generating assets, operating characteristics of potential new generating units, and environmental regulations (current and planned). The capacity expansion model uses these inputs to determine a future business-as-usual build-out of the system through an optimization process that chooses the least-cost solution to adding capacity.
Step 2	Develop a DER Case forecast This forecast should include the addition of the DERs being tested for cost-effectiveness over the study period (see Section 2.5). This step involves rerunning the model with the same assumptions except for the addition of DERs over the study period. While capacity expansion models can endogenously select the DER as part of a least-cost portfolio solution, this is not typically done due to data quality issues for DER load impact profiles.
Step 3	Calculate the marginal impact The marginal impact should be calculated by taking the difference in capacity additions between Steps 1 and 2 to calculate the marginal capacity cost per MW based on the annualized capital and fixed costs for all the added resources for the BCA study period.

Method 2: Capacity Market Simulation

This method is typically used to develop avoided generation capacity costs for jurisdictions with a capacity market. It is typically run with a production cost model since capacity markets bids and clearing prices rely on accurate energy and ancillary prices that are better determined through a production cost model. Table 19 outlines steps for using this method.

Table 19. Steps for developing avoided generation capacity costs using capacity market simulation

Step 1	Develop a Reference Case forecast for how future load will be met This involves entering the following inputs into the model: the projected growth in electricity demand, changes in energy and fuel prices, existing fleet of generating assets, operating characteristics of potential new generating units, and environmental regulations (current and planned). The capacity expansion model uses these inputs to determine a future business-as-usual build-out of the system through an optimization process that chooses the least-cost solution to adding capacity. Importantly, this forecast should not include any DERs that will be tested for cost-effectiveness. It may contain other DERs that are not part of the current cost-effectiveness analysis.
Step 2	Run the capacity expansion model (and potentially the production cost model) This process will determine the future resource build-out on the system and simulate dispatch of the resources.

The model will output avoided capacity costs in the form of capacity prices (see U.S. EPA 2018).

The primary advantages of the power sector modeling method include its ability to provide granular pricing (hourly and sub-hourly), which can provide a more detailed assessment of how DERs will impact generation. The primary disadvantages include its complexity, required technical expertise, and licensing fees.

Examples of Production Cost and Capacity Expansion Models

See Section 3.2.1.b, Table 8.

Key Data Sources for Capacity Expansion Models

See Section 3.2.1.b.

The states of California and Hawaii demonstrate use of power sector models to analyze generation capacity impacts, shown in Table 20 below.

Table 20. State examples using the power sector model method to estimate generation capacity impacts

State	Summary
California	California uses the RESOLVE capacity expansion model and uses a battery storage resource as the proxy for new capacity instead of gas combustion turbine. The capacity avoided cost component was based on the Net CONE of battery storage, using the IRP cost and configuration assumptions and RESOLVE storage build. (See CPUC 2020.)
Hawaii	Hawaii has historically used the EnCompass model to calculate annual carrying costs associated with planned capacity additions between 2021 and 2025 on an annual basis. Allocation factors were calculated for both storage and solar resources, and total carrying costs were allocated to on-peak and off-peak hours. Hawaiian Electric plans to use a combination of the RESOLVE & PLEXOS models going forward.

Option 5: Publicly Available Generation Capacity Impacts

It is sometimes possible to use generation capacity impacts provided by publicly available sources, instead of the methods described above. The following is a list of publicly available data sources (see U.S. EPA 2018).

Historical Information

Historical energy cost data cannot be directly used as inputs for forward-looking BCAs. Nonetheless, historical energy cost data might be helpful as a starting point for developing forecasts or as a benchmark against which to evaluate forecasts.

- FERC Form 1 provides information for dispatch curve analyses. (See FERC Form 1.)
- SEC 10-Q Filings: Quarterly reports can provide company information on historical financial data and are available from the SEC EDGAR system. (See U.S. SEC EDGAR.)
- Securities and Economic Exchange Commission 10K Filings. The annual filings can provide individual utility historical financial data. (See U.S. SEC EDGAR.)

Forecasts

- Regional Reliability Organizations. For example, NERC has information on required reserve margins. (See NERC website.)

- NREL's Jobs and Economic Development Impact (JEDI) model. Calculates the economic cost and impacts of constructing power generation assets including plant construction costs and fixed costs. (See NREL Jedi.)
- *Avoided Energy Supply Components in New England: 2021 Report* provides avoided generation capacity impacts for the six New England States. (See AESC 2021.)
- California Avoided Cost Calculator provides avoided generation capacity impacts for DERs deployed in the state of California. (See CPUC 2021; E3 EE.)

Option 6: Proprietary Generation Capacity Impact Forecasts

Utility filings in resource planning and plant acquisition proceedings often contain long-run avoided costs of power plant capacity. However, utility forecasts are often proprietary. Typically, the only way for non-utility stakeholders to obtain proprietary forecasts is through a docketed case where discovery is permitted.

Accounting for Changes in Reserve Margins

Many electric utilities use a planning reserve margin to ensure that sufficient generation capacity will be available when needed. The reserve margin can vary by utilities and region. They should account for the reliability and operating characteristics of the applicable electricity system. For example, if a utility's reserve margin is 15 percent and its peak demand is expected to be 100 GW, then it will plan to have 115 GW of capacity installed to ensure that sufficient capacity will be available at the time of peak demand.

DERs can affect the amount of capacity needed to meet the reserve margin by reducing or increasing customer demand. DERs that reduce customer demands, such as energy efficiency, demand response, and distributed generation, will create reserve margin benefits. DERs that increase customer demands, such as building electrification and electric vehicles, will create reserve margin costs.

This planning reserve margin impact can be calculated by multiplying the DER capacity impact (in $ or $/kW) by the planning reserve margin (in %). For example, if a utility has a 15 percent reserve margin, a 10 kW distributed generation resource would actually provide 11.5 kW of capacity benefits because it (a) provides 10 kW of power and (b) reduces the need for 1.5 kW of capacity needed to meet the reserve margin.

3.2.2.c. Choosing a Method to Calculate Generation Capacity Impacts

Table 21 provides a brief description of the advantages and disadvantages of common methods for estimating generation capacity impacts.

Table 21. Advantages and disadvantages of common methods to calculate generation capacity impacts

Method	Description	Advantages	Disadvantages
Proxy Unit	Identifies the next planned generation resource to be built and uses its operational costs as a proxy for avoided energy	Simple approach; information available to those outside of utility; does not require detailed data or modeling; inexpensive	May produce inaccurate costs; may not apply to DERs with vastly different load impact profiles; does not reflect displacement of baseload units long-term; may miss interactive effects
Peaker Plant	Identifies the least-cost capacity option available on the system; capacity-related portion of the unit's fixed costs assumed to represent the avoided cost of generation capacity	Simple approach. Information available to those outside of utility. Does not require detailed data or modeling. Inexpensive.	May underestimate costs; may not reflect policy goals of state
Market Data	Uses wholesale electricity prices, which reflect the actual costs for operating marginal units in the bids that generators submit	Relatively simple approach; captures regional variation. Based on local generation mix; includes transmission congestion	Potential to double-count impacts with other avoided costs
Power System Modeling	Simulates generation and transmission capacity investment, based on assumptions about future demand, fuel prices, resource cost and performance, and policy and regulation	High level of accuracy; captures complex interactions; captures avoided variable costs; can cover longer timeframe up to 40 years; can estimate changes in emissions due to generation mix; can incorporate dispatch characteristics	Requires technical expertise and is labor intensive and expensive; lacks transparency due to complexity; choice and accuracy of model impacts are critical to accurate outcomes
Public and Proprietary Forecasts	Use publicly available historical energy cost data as benchmark for making forecasts. Use publicly available or proprietary forecasts as inputs.	Simple approach; information available to those outside of utility; does not require detailed data or modeling; inexpensive.	May not be as granular as desired; may not be as accurate or as up-to-date as other methods; proprietary forecasts might be expensive or unavailable to some stakeholders

3.2.2.d. Resources for Calculating Generation Capacity Impacts

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3.2.3. Renewable and Clean Energy Standard Compliance

3.2.3.a. Definition

In jurisdictions that have adopted a renewable portfolio standard (RPS) or similar regulatory mechanisms like clean energy standards (CES) or clean peak standards (CPS), DERs can impact the cost of compliance. DERs can reduce compliance costs either by reducing the target by virtue of lowering overall electricity demand or increasing the level of qualified renewable or clean energy generation. Alternatively, if a DER has the effect of increasing electricity demand (e.g., electrification) it will require additional renewable purchases and therefore increase the compliance costs of meeting the standard.

3.2.3.b. Methods for Calculating Renewable and Clean Energy Standard Compliance Impacts

Figure 11 summarizes the common methods for quantifying or informing energy generation impacts, each of which is described in detail below. Section 3.2.1.c summarizes the advantages and disadvantages of each method.

Figure 11. Methods for estimating renewable and clean energy standard compliance impacts

Wholesale Electricity Markets Method	Vertically Integrated Utilities: Proxy Unit Method	Vertically Integrated Utilities: Modeling Method
• Determine compliance requirements • Develop REC price forecasts • Calculate compliance cost per MWh reduction	• Choose a proxy unit that represents a typical conventional generator on the system • Compare costs (i.e., fuel, generation capacity, O&M, transmission, ancillary services, emissions) of RPS resources with the levelized cost of the proxy unit	• Use dispatch and capacity expansion models to model generation built and dispatched with and without the addition of new renewable energy generation.

Option 1: Wholesale Electricity Markets

For states that have restructured electricity markets, the avoided cost of RPS compliance is typically a function of both the renewable energy certificate (REC) price and load obligation percentage (i.e., the RPS target percentage).

Calculating this impact involves the steps in Table 22.

Table 22. Steps to calculate RES and CES impacts using wholesale electricity market data

Step 1	Review standard to determine compliance requirements This includes identifying the annual requirements and how they scale over the long term, whether there are different requirements for subcategories or tiers of resources (e.g., new vs. existing resources), and how utilities meet their obligation (e.g., purchasing RECs, building renewable supply, alternative compliance payments).
Step 2	Develop REC price forecasts These should be prepared for each RPS sub-category (if applicable) using forecasts of eligible supply, annual demand targets, and the long-term cost of entry of renewable energy additions. REC prices for "new" resources, where the RPS mandate indicates commercial operation must be achieved after a certain date, are typically based on the cost of new entry for the renewable energy resource. Whereas REC prices for existing resources are typically a function of supply, demand, interaction with other state's mandate, and alternative compliance payments. (See AESC 2021, pgs. 152-162.)
Step 3	Calculate the compliance cost per MWh reduction This step calculates the RPS compliance cost that DERs avoid or incur through reductions or increases in energy usage. This value can be calculated with the following equation (See AESC 2021): $\frac{\sum_n P_{n,i} \times R_{n,i}}{1-l}$ Where: i = year n = RPS classes Pn,i = projected price of RECs for RPS class n in year i, Rn,i = RPS requirement, expressed as a percentage, for RPS class n in year i, l = losses from ISO wholesale load accounts to retail meters (%)

Table 23 below provides examples of using wholesale electricity market data to estimate Renewable and Clean Energy Standard compliance impacts.

Table 23. State examples of estimating compliance impacts in wholesale electricity markets

State	Summary
New York	The compliance cost associated with New York's Clean Energy Standard (CES) is valued as the resulting $/MWh of a REC from the most recently completed New York State Energy Research and Development Authority RECs solicitation. (See ConEdison 2020.)
Maryland	The EmPOWER energy efficiency programs assume that avoided renewable energy requirements result in cost savings that are determined by projecting REC prices. There are different REC prices for Maryland Tier 1 RECs, Maryland Tier 2 RECs, and Maryland Solar RECs. For near-term values, REC prices were based on the futures market for Maryland RECs. For long-term values, Solar REC prices and Tier I REC prices were determined through modeling. Specifically, REC prices were developed by estimating the REC revenue needed to support a 200-MW wind project (Tier 1 REC) and a 10-MW utility-scale solar project (Solar REC). A gap analysis approach was used to determine the REC price necessary to make a wind or solar project economic after accounting for: (1) the capital cost of the project; (2) the cost of capital; (3) O&M expenses; (4) taxes; (5) revenue obtained from the sale of energy and capacity; and (6) the federal investment tax credit (for solar only) (see Exeter Associates 2014, pgs. 19-23).
Pennsylvania	The Act 129 energy efficiency programs include the benefit of avoided compliance costs with the state's Alternative Energy Portfolio Standards Act (AEPS). The Public Utility Commission has access to several subscription-based services that forecast AEC pricing, including Marex Spectron. (See PA PUC 2020.)

The primary advantages of this method are that it is a relatively simplistic method and wholesale market data is readily available. The primary disadvantages include that power purchase agreement prices may be proprietary outside of the utility and this approach does not consider the load impact profile of the renewable energy resource and therefore does not consider contribution to on-peak and off-peak periods.

Options 2A and 2B - Vertically Integrated Utilities

The methods for calculating avoided RPS compliance costs for vertically integrated utilities typically involve comparing the cost of procuring the required renewable generation against the cost of procuring the same amount of conventional generation. There are two main methods for this approach (see NREL 2014 DPV):

Option 2A: Proxy Unit Method

This method compares the costs (i.e., fuel, generation capacity, O&M, transmission, ancillary services, emissions) of RPS resources with the levelized cost of a proxy unit that is meant to represent a typical conventional generator on the system. Table 24 below provides examples of states using this method.

The primary advantages of this method are that it is a relatively simplistic method that provides for a long-term outlook by taking the levelized cost over the generation resource life. The primary disadvantages include that it does not account for load impact profiles of renewable resources and does not reflect the fact that RPS requirements could displace more than one type of generation. The proxy unit therefore may not reflect the conventional generation being avoided by the RPS resources, leading to inaccurate avoided costs.

Table 24. State examples using the proxy unit method to estimate compliance impacts

State	Summary
Michigan	The PUC is required to determine the cost-effectiveness of the state's Renewable Energy Standard (RES) as compared to the life-cycle cost of electricity of coal-fired generation. The PUC includes this information where it compares the levelized cost of $133 per MWh for a new coal plant with the combined weighted average levelized renewable energy contract prices for each utility, by RPS technology. In its 2020 report, the PUC noted that "Comparing per unit energy costs of different generation types may not reflect the true value of the resource to the reliability of the electric system as a whole." (See MPSC 2020, pgs. 16-19.)
Oregon	The incremental cost of compliance with the RPS is based on the cost of a combined cycle gas turbine (CCGT), using those filed in the most recent IRP. The proxy type can be changed by the PUC. (See NREL 2014 RPS.)

Option 2B: Modeling Method

Similar to the modeling approaches for calculating energy generation impacts, dispatch and capacity expansion models can be used to determine the avoided cost of RPS compliance. This method models generation built and dispatched with and without the addition of new renewable energy generation. Table 25 below shows an example of a state using this method.

The primary advantage of this method is that it produces more accurate results compared to the proxy unit method by producing a comprehensive system view of what would have occurred without the RPS. The primary disadvantages are that it is time intensive, expensive, and lacks transparency due to the complexity of the model.

Table 25. State example using the modeling method to estimate compliance impacts

State	Summary
New Mexico	Public Service Company of New Mexico (PNM) calculated RPS costs using a production cost model. PNM models the total system costs with and without each existing and proposed renewable resources to determine the avoided fuel cost for each resource. (See NREL 2014 RPS.)

3.2.3.c. Resources for Renewable and Clean Energy Standard Compliance Impacts

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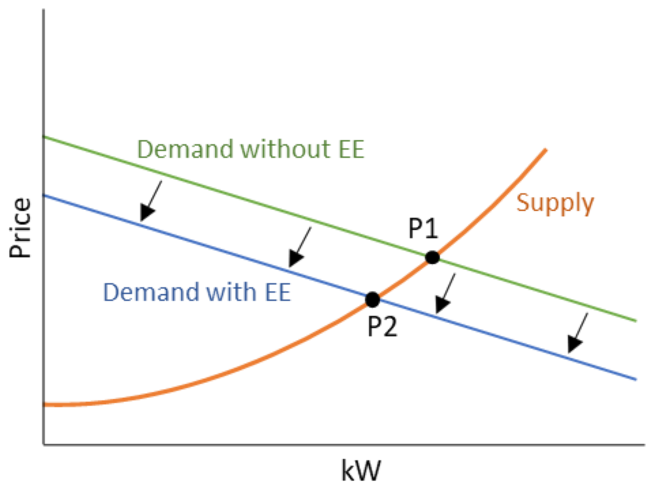
3.2.4. Wholesale Market Price Effects

3.2.4.a. Definition

In jurisdictions with competitive wholesale electricity markets, wholesale market prices are a function of the demand of buyers and the marginal costs of suppliers at any given instant. When DERs reduce (or increase) the demand for electricity, they reduce (or increase) the wholesale market prices. This change creates benefits (or costs) for all customers participating in the wholesale market at that time. This effect is sometimes referred to as demand reduction induced price effect (DRIPE).

Figure 12 below shows how a reduction in demand (in this case due to energy efficiency) lowers electricity prices (see Action 2015). Introducing energy efficiency into the market reduces the need to purchase higher cost resources, which will lessen the need for additional generation resource investments. The price delta between the intersection of the supply and the Demand without energy efficiency curves (P1) and the intersection of the Supply and the Demand with energy efficiency curves (P2) is the DRIPE effect. This model holds true provided that the marginal cost of electricity is higher than the average cost.

Figure 12. Theoretical effect of DRIPE on the price of electricity



Source: Adapted from DOE 2015, State Approaches to Demand Reduction Induced Price Effects: Examining How Energy Efficiency Can Lower Prices for All, December, page 7.

DERs can impact wholesale market prices either in the form of demand (e.g., distributed solar PV treated as a utility load modifier) or supply (e.g., demand response participation directly in the wholesale market). This impact typically lasts for only a short period before the market adjusts to the new supply/demand balance.

3.2.4.b. Methods for Calculating Wholesale Market Price Effects

The calculation of wholesale market prices effects is dependent on market prices, the size of the market, and the price responsiveness of the market. Figure 13 summarizes two common methods for calculating wholesale market price suppression effects.

Figure 13. Methods for estimating wholesale market price effects

Dispatch Curve Analysis

- Determine energy saved or generated by DER
- Develop dispatch curve
- Use dispatch curve to analyze Reference Case
- Use dispatch curve to analyze DER Case
- Take the difference in the wholesale market price between the Reference Case and the DER Case

Combination Analysis

- Calculate the price shift
- Multiply the price shift by total future market demand to create a price-per-demand value
- Adjust the price-per-demand value according to how market operation impacts the total price, timing, and duration of DRIPE

Option 1: Dispatch Curve Analysis Method

This method involves the steps in Table 26 and can be used for calculating either wholesale energy or capacity market price effects (see EPA 2018, pages 3-34 to 3-36).

Table 26. Steps to calculate wholesale market price effects using the dispatch curve analysis method

Step 1	Determine the energy saved or generated by the proposed DER This can be determined using the proposed DERs' load impact profiles (see Chapter 11). Ideally, the savings or generation would be developed on an hourly basis, to reflect the variation across different time periods.
Step 2	Develop a dispatch curve See EPA 2018, Section 3.2.4, beginning on page 3-11.
Step 3	Use the dispatch curve to analyze the Reference Case This is the expected level of electricity demand and resulting costs without the DERs under analysis.
Step 4	Use the dispatch curve to analyze the DER Case This is the expected level of electricity demand and resulting costs with the DERs being analyzed.
Step 5	Take the difference in the wholesale market price between the Reference Case and the DER Case The resulting $/MWh is the wholesale market price effect.

Models for Dispatch Curve Analysis Method

This method can be conducted using either spreadsheets, an economic dispatch model like GE MAPS or PROMOD IV, or an energy system model. These tools use data sources such as those provided in Table 27.

Table 27. Key data sources for dispatch curve analysis method

	Data Source	Description
Generator Unit Data	ABB's Velocity Suite	Velocity Suite provides information on market participants and industry dynamics across commodities. new.abb.com/enterprise-software/energy-portfolio-management/market-intelligence-services/velocity-suite
	Platts' MegaWatt Daily	Platts publishes forward electricity market prices through this paid subscription newsletter. www.platts.com/products/megawatt-daily
	U.S. EIA's Annual Energy Outlook	This resource provides long-term electricity and fuel price projections. www.eia.doe.gov/oiaf/aeo/index.html
	U.S. EIA's Electricity Data	Operating cost and historical utilization data is typically available from the EIA or the local load balancing authority. Often these sources can also provide generator-specific emissions rates for estimating potential emissions reductions from energy efficiency and renewable energy. www.eia.gov/electricity/
	U.S. EIA's Form EIA-860	This form provides generator-level information about existing and planned generators and associated environmental equipment at electric power plants with 1 MW or greater of combined nameplate capacity. www.eia.gov/electricity/data/eia860/
	U.S. EIA's Form EIA-861	This form provides information such as peak load, generation, electric purchases, sales, revenues, customer counts and DSM programs, green pricing and net metering programs, and distributed generation capacity. www.eia.gov/electricity/data/eia861/
	U.S. EIA's Form EIA-923	This form contains generator and fuel cost data by plant and can be used as an indicator for operating costs. www.eia.gov/electricity/data/eia923/
	U.S. EPA's eGRID Database	This database provides historical data on or estimates of capacity factors for individual plants which can be used in displacement curve analysis. www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid
	FERC Form 1	Filed annually by major electric utilities. This comprehensive financial and operating report can be used as a source of data for dispatch curve analysis. https://www.ferc.gov/general-information-0/electric-industry-forms/form-1-electric-utility-annual-report
	FERC Form 423	Compilation of data for cost and quantity of fuels delivered to electric power plants. https://www.ferc.gov/industries-data/electric/resources/industry-forms/form-no-423-cost-and-quality-fuels-electric
	FERC Form 714	This form can provide data on control area hourly marginal costs. https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/overview
Market Clearing Prices	ISO-NE Forward Capacity Market (FCM)	www.iso-ne.com/markets-operations/markets/forward-capacity-market/
	PJM Reliability Pricing Model (RPM)	www.pjm.com/markets-and-operations/rpm.aspx
	NY-ISO Installed Capacity Market (ICAP)	www.nyiso.com/installed-capacity-market

Generator unit data sources: see EPA 2018, pages 3-51 to 3-52.

Option 2: Combination Analysis Method

The AESC 2021 calculates DRIPE for the New England states using a combination of quantitative analyses based on national and New England data instead of modeling projected market conditions. The AESC uses the three-step framework summarized below as the basis to calculate various forms of DRIPE, including energy DRIPE, capacity DRIPE, and cross-DRIPE. The steps, shown in Table 28, become more or less complex depending on the type of DRIPE being calculated. (See AESC 2021, pages 193-230.)

Table 28. Steps to calculate wholesale market price effects using the combination analysis method

Step 1	**Calculate the price shift** This is the change in price due to a change in demand. Depending on the availability of data, this can be calculated using a regression from historical data or based on an assumed supply curve. The AESC uses a regression to calculate energy DRIPE and uses the slope of the most recent New England Forward Capacity Auction supply curve and EnCompass model outputs to calculate capacity DRIPE.
Step 2	**Multiply the price shift by total future market demand** This creates a price-per-demand value. This step allows for the price shift to be applied to any generic change in demand. Specific to the calculation of capacity DRIPE, the AESC calculates two varieties of capacity DRIPE effects: • Cleared DRIPE benefits, which are benefits of measures that clear in the ISO-NE Forward Capacity Market (FCM). (See AESC 2021, pgs. 211-212.) • Uncleared DRIPE benefits, which are benefits of measures that are not submitted into or otherwise do not clear in the ISO-NE FCM. (See AESC 2021, pgs. 213-214.)
Step 3	**Adjust the price-per-demand value** This step involves estimating the way market operation impacts the total price, timing, and duration of DRIPE. For example, in calculating energy DRIPE, the AESC reduces the value of DRIPE by the portion of demand that was not already purchased through long-term contracts. This can also have the effect of delaying the realization of DRIPE impacts for several years. The value is further adjusted to reflect the fact that electricity generators will gradually react to the new market price, thereby eroding the price effects from DERs over time.

The resulting DRIPE values are provided for each state in intra-zonal terms (including only those benefits associated with load impacts within a zone) and inter-zonal terms (also referred to as rest-of-pool) where benefits accrue outside state borders. Energy DRIPE results are provided in $/kWh and can be applied to DER energy savings or increases in each of the four costing periods (summer on- and off-peak, winter on- and off-peak). Capacity DRIPE results are in $/kW and should be applied to changes in peak energy demand.

Key Data Sources for Combination Analysis Method

- Energy Price data can be obtained from ISOs
  - Hourly energy price data and gross load data for ISO-NE. (See ISONE Hourly Data.)
  - Sub hourly data for ISO-NE fuel mix. (See ISONE Fuel Mix.)
- Daily data on delivered prices to Algonquin Citygate available from Natural Gas Intel’s “Algonquin Citygate Daily Natural Gas Price Snapchat.” (See NGI 2021.)

Table 29 describes how three states use the combination analysis method to estimate wholesale market price effects.

Table 29. State examples using the combination analysis method

State	Summary
Washington D.C.	Value of solar study used a 2014 study of PJM's energy DRIPE that determined a DRIPE energy ratio of 1.17, implying that every 1 percent reduction of energy consumption results in a 1.17 percent reduction in price. DRIPE is shared throughout the RTO, therefore the value to D.C. is roughly 1.57 percent of the benefits. The remaining 98.43 percent of the energy DRIPE benefits flow to other PJM ratepayers and represent a societal benefit. Due to generator build and retirement within PJM, the study assumed DRIPE energy benefits dissipate quickly, in a linear manner over a five-year timeframe. (See Synapse 2017)
Maryland	Maryland uses a market simulation model (Ventyx) to forecast future energy and capacity values in specific zones located within PJM. The model is run with and without energy efficiency to calculate the change in price. The resulting price is adjusted for each zone, for the state, and to account for decay over time. (See Exeter 2014 pgs. 32-43)
New Jersey	The recent New Jersey Cost Test framework calculates energy DRIPE by "regressing historical electric energy prices as a function of load to determine the impact of load on electric energy prices" and calculates capacity DRIPE "using a linear extrapolation of price differentials between auction results and the scenario in which PJM removes 3000 MW of capacity supply from the bottom of the supply curve in MAAC." (See NJ BPU 2020)

3.2.4.c. Resources for Calculating Wholesale Market Price Effects

Avoided Energy Supply Components Study Group. 2021. (AESC 2021). *Avoided Energy Supply Components in New England: 2021 Report*. Prepared by Synapse Energy Economics, Resource Insight, Les Demans Consulting, Northside Energy, Sustainable Energy Advantage.

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3.2.5. Ancillary Services

3.2.5.a. Definition

Ancillary services are those services required to maintain electric grid stability. They typically include frequency regulation, voltage regulation, spinning reserves, and operating reserves. These services are either traded in wholesale energy markets or self-supplied by utilities.

A DER's net effect on ancillary services depends on its load impact profile and what the real-time system conditions are at the time of its operation. Some resources may be actively dispatched to provide ancillary services (for instance, storage providing frequency regulation). Alternatively, even if a DER's operation is not directly in response to a signal to provide ancillary services, it may nevertheless create an impact. For example, during times when load is ramping up quickly and/or generation resources are ramping down quickly, DERs can provide additional operating reserves, fast frequency response, or ramping services. Excess renewable generation is creating the need for new ancillary services such as load build, fast frequency response, shimmy, and shift. As grid architecture likely evolves to achieve clean energy goals, the role of the distribution utility will also need to evolve. This evolution will create DER planning opportunities for additional capacity and ancillary services within distribution resource planning processes.

A DER that reduces energy consumption would create a benefit by avoiding the average ancillary service price, whereas a DER increasing usage would create a cost equal to the average price.

3.2.5.b. Methods for Calculating Ancillary Services Impacts

Figure 14 summarizes two common methods for calculating ancillary services impacts.

Figure 14. Methods for calculating ancillary services impacts

Historical Market Data Method	Production Cost Model Method
• Historical data from wholesale markets to determine the average price that DERs would receive from participating in ancillary services markets • Analyze data to determine trends that can be used to project future prices	• Use model to calcuate revenues based upon DER's ability to participate in various ancillary services markets • Model selects the optimal dispatch of resources between energy and ancillary services based on a combination of load and availability and capability of DERs

Option 1: Historical Market Data Method

This method relies on historical data from wholesale markets to determine the average price that DERs would receive from participating in ancillary services markets. The historical data can be analyzed to determine trends than can be used to project prices into the future.

One useful example of this method is Pepco's BCA for Locational Constraint Solutions (LCS) to calculate the impact of DERs on Regulation and Operating Reserves (See Pepco 2020). This example is described below.

The calculation for regulation revenue is as follows:

$$Regulation\ Revenue_{Class,Year} * Installed\ Capacity_{Class,Year} = Avoided\ Regulation\ Benefit_{Year}$$

Where:

Regulation Revenue$_{Class,Year}$ ($/MW-Year) is PJM's most recent forward-looking regulation service revenue estimate used to determine the RPM parameters for the technology class of the DERs making up the LCS. For historical or future delivery years, the revenue estimate is adjusted for inflation. If PJM does not calculate a value for regulation revenue for the LCS DERs, then the LCS does not receive this benefit stream.

Installed Capacity$_{Class,Year}$ (MW) is the LCS's project-specific projected Installed Capacity rating, determined in accordance with the market rules of the PJM RPM.

The calculation for Operating Reserves is as follows:

$$SR\ Revenue_{Class,Year} * Installed\ Capacity_{Class,Year} + NRSR_{Class,Year} * Installed\ Capacity_{Class,Year} + 30\ Minute\ Reserve\ Revenue_{Class,Year} * Installed\ Capacity_{Class,Year} = Avoided\ Operating\ Reserve\ Benefit_{Class,Year}$$

Where:

SR Revenue$_{Class,Year}$ ($/MW) is PJM's most recent forward-looking synchronized reserve service revenue estimate used to determine the RPM Base Residual Auction parameters for the technology class of the DERs making up the LCS. This value is normalized to revenues per MW of Installed Capacity for each technology class. For historical or future delivery years, the revenue estimate is adjusted for inflation.

NSR Revenue$_{Class,Year}$ ($/MW) is PJM's most recent forward-looking non-synchronized reserve service revenue estimate used to determine the RPM Base Residual Auction parameters for the technology class of the DERs making up the LCS. This value is normalized to revenues per MW of Installed Capacity for each technology class. For historical or future delivery years, the revenue estimate is adjusted for inflation.

30 Minute Reserve Revenue$_{Class,Year}$ ($/MW) is PJM's most recent forward-looking 30-minute reserve service revenue estimate used to determine the RPM Base Residual Auction parameters for the technology class of the DERs making up the LCS. This value is normalized to revenues per MW of Installed Capacity for each resource class. For historical or future delivery years, the revenue estimate is adjusted for inflation.

Installed Capacity$_{Class,Year}$ (MW) is the LCS's project-specific projected Installed Capacity rating, determined in accordance with the market rules of the PJM RPM.

Key Data Sources for Market Data Method

Market prices can be obtained from RTOs and ISOs with markets for ancillary services at the locations shown below.

Ancillary Services Market Data:

- NYISO: https://www.nyiso.com/ancillary-services
- PJM: www.pjm.com/markets-and-operations/ancillary-services.aspx
- ISO-NE: www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/ancillary
- ERCOT: www.ercot.com/mktinfo/rtm
- CAISO: www.caiso.com/participate/Pages/MarketProducts/AncillaryServices/Default.aspx

The primary advantage of this method is its simplistic approach that does not involve modeling and is based on publicly available data. The primary disadvantages are that it assumes historical ancillary service prices trends will continue, which may not always be the case as the electricity system changes significantly in the future. This method also relies on historical data that may not be available where no wholesale markets exist. Table 30 describes how two states use this method.

Table 30. State examples using the historical market data method to estimate ancillary services impacts

State	Summary
New York	Avoided ancillary service costs are calculated using the two-year historical NYISO market clearing prices. Likewise, if DERs are anticipated to increase ancillary service costs, the additional cost is calculated using the two-year historical NYISO market clearing prices. (See ConEdison 2020.)
New Jersey	New Jersey uses a three-year rolling average of historical prices multiplied by the quantity of ancillary services products not purchased. (See NJ BPU 2020.)

Option 2: Production Cost Model Method

This method uses a production cost model to estimate the value of future ancillary services. Revenues are calculated based upon the DER's ability to participate in various ancillary services markets. The model considers the energy and ancillary components for a specific region through characterization of inputs such as fuel costs, electric load, generating unit characteristics, and transmission constraints. The model selects the optimal dispatch of resources between the energy and the ancillary services based on a combination of load and the availability and capability of DERs.

The model user can choose to conduct a more detailed modeling approach by setting a regional or system-wide requirement for ancillary services. This requirement may include, but is not limited to, operating reserves, spinning reserves, and regulation up and down requirements at an hourly or intra hourly level. Similarly, the model user can specify ramp rates, minimum capacity, and response times for various DERs at the resource or unit level to determine the contribution of various resources towards ancillary services.

This method uses a similar set of data sources as what is required for the product cost model method for energy generation as detailed in Section 3.2.1.b.

The primary advantages of this method are that it can more accurately reflect the electricity system in the future and is able to optimize dispatch across both energy and ancillary service requirements simultaneously. This model can be used for different temporal granularities (i.e., hourly, intra hourly).

The primary disadvantages are that it is resource intensive and requires the expertise to operate the model. Table 31 describes how two states use this method to estimate ancillary services impacts.

Table 31. State examples using the production cost model method to estimate ancillary services impacts

State	Summary
California	Ancillary services impacts were derived from SERVM production simulation that calculated the net market revenues a battery storage unit, assuming optimal dispatch. Prices are extrapolated beyond the model's output using a compound annual growth rate. (See CPUC 2020, pages 17-18.)
Hawaii	The EnCompass model was used in a recent value of DER study to estimate the marginal costs of ancillary services. Ancillary services were modeled as a 30-minute minimum reserve requirement, which represented the resource's maximum time to ramp up to contribute to reserves. (See Synapse 2021 HI, pg. 8.)

3.2.5.c. Resources for Calculating Ancillary Services Impacts

Avoided Energy Supply Components Study Group. 2021. (AESC 2021). *Avoided Energy Supply Components in New England: 2021 Report*. Prepared by Synapse Energy Economics, Resource Insight, Les Demans Consulting, Northside Energy, Sustainable Energy Advantage.

California Public Utilities Commission. 2020. (CPUC 2020). *Distributed Energy Resources Avoided Cost Calculator Documentation for the California Public Utilities Commission*. Version 1c. Prepared by Energy and Environmental Economics, Inc. June.

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New Jersey Board of Public Utilities. 2020. (NJ BPU 2020). In the Matter of the Clean Energy Act of 2018 – New Jersey Cost Test. Docket Nos. QO19010040 & QO20060389.

Pepco. 2020. Benefit-to-Cost Analysis Handbook for Locational Constraint Solutions. Docket FC1130.

U.S. Environmental Protection Agency. 2018. (U.S. EPA 2018). *Quantifying the Multiple Benefits of Energy Efficiency and Renewable Energy: A Guide for State and Local Governments*. www.epa.gov/statelocalenergy/quantifying-multiple-benefits-energy-efficiency-and-renewable-energy-guide-state.

Synapse Energy Economics. 2021. (Synapse 2021 HI). *Development of Time-of-Use Rate Options for Hawaii*, filed in Advanced Rate Design Track, Docket 2019-0323. Whited, M., S. Liburd, A.S. Hopkins, A. Takasugi, D. Bhandari, R. Fagan. Prepared for Hawaii Division of Consumer Advocacy.

3.2.6. Environmental Compliance Impacts

3.2.6.a. Definition and Overview

There are many environmental requirements that impact the electric utility system. Utilities experience environmental compliance impacts and pass them on to all customers through revenue requirements and rates. In many cases, DERs will help to reduce the costs of environmental requirements by reducing air emissions and other environmental impacts of electricity generation, transmission, and distribution. In some cases, DERs might increase the costs of environmental requirements, for example if they create a net increase in GHG or criteria pollutant emissions.

Sources of Environmental Requirements

Some of the key environmental regulations that impact the electricity industry include:

- Federal regulations such as the Clean Air Act, the Clean Water Act, and the Resource Conservation and Recovery Act.
- Federal, regional, state, or local GHG emission mandates.
- State or local air, land, or water emission constraints.

The most prevalent environmental requirements for the electricity industry can be grouped into the categories shown in Figure 15.

Figure 15. Common environmental requirements with the electricity industry

Pollutant cap-and-trade or market-based mechanisms

- These requirements generally impose a cap on total emissions across a regulated category of units, and then allow more flexibility in compliance by allowing allowances for emissions under this cap to be traded between entities. Key to the determining regulatory costs under these programs is how the allowances are allocated to market participants, which can significantly affect cost of compliance. Examples include the federal U.S. Acid Rain Program for sulfur dioxide emissions and Cross-State Air Pollution Rule (see U.S. EPA CMD); the Regional Greenhouse Gas Initiative in the Northeast (see RGGI, n.d.), and the California GHG Cap-and-Trade Program (see CA ARB 2021).

GHG Emission mandates or targets

- GHG mandates or targets are an increasingly common type of environmental compliance costs. These mandates specify emission reductions relative to a benchmark amount (e.g., 1990 emissions) or sometimes place a cap on total emissions (as in cap-and-trade above). They sometimes limit emissions by a single target year (e.g., 2030), or sometimes limit emissions by increasing amounts for several target years (2030, 2040, 2050). Mandates are legally required, while targets are generally not legally binding. An example of a federal GHG target is the U.S. Nationally Determined Contribution, a 2030 emissions target submitted under the Paris Climate Agreement. Emissions mandates may also be expressed in the form of an emissions rate per unit of electricity. Certain regulatory requirements, like new source performance standards under the U.S. Clean Air Act, are based on an evaluation of available emissions reductions technologies, but are ultimate expressed in the form of an emission mandate (see U.S. 2021 NDC).

Pollution control equipment

- Pollution control equipment costs can include capital, fixed O&M, variable O&M, and fuel costs. Pollution control equipment can be installed at the time of construction of the generation facility, or it can be retrofitted after the facility has been in operation. Fuel switching is another strategy for pollution control in existing plants, and that may or may not require capital investment. For example, many coal plants complied with the U.S. Acid Rain Program by switching from high-sulfur to low-sulfur coal, which did not require significant retrofits. Conversely, switching a coal plant to natural gas co-firing will require a higher level of capital investment (see RAP 2013).

Fees and permits

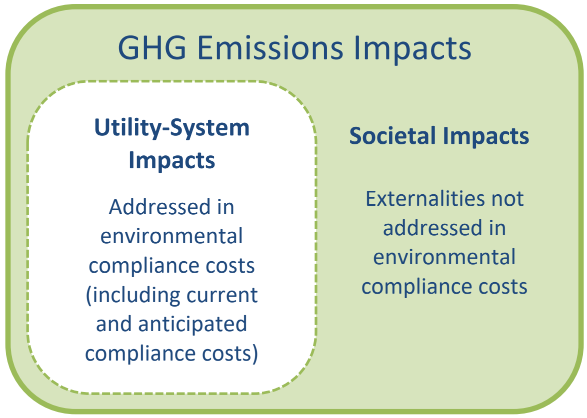
- The federal Clean Air Act requires most generators to obtain construction permits, as well as an operating permit that requires periodic renewal. State air agencies often impose emission fees on electricity generators for criteria air pollutants (see RAP 2013, pages 31-32).

Relationship to Societal Environmental Impacts

Societal environmental impacts are the impacts on the environment that occur in the absence of environmental requirements or after the environmental requirements have been met. It is important to distinguish between environmental compliance impacts and societal environmental impacts.[4]

- Environmental compliance impacts are the direct impacts in dollar terms that will be incurred by the utility and passed on to all customers through revenue requirements and customer rates.
- Societal environmental impacts are imposed on society as a whole but do not affect the cost of electricity services.

Figure 16. Distinction between societal and utility-system GHG emissions impacts



This distinction, depicted in Figure 16, is important for two reasons. First, environmental compliance impacts are utility system impacts that will be paid by utility customers and therefore should be included in all BCA tests.[5] Societal environmental impacts, on the other hand, do not reflect direct costs that will be paid by utility customers and therefore should be included only in a BCA test if that would be consistent with the jurisdiction's policy goals.

Second, environmental compliance impacts will have very different rate and bill impacts than societal environmental impacts. Environmental compliance impacts will affect utility rates and bills, and therefore should be included in rate, bill, and participation analyses. Societal environmental impacts, on the other hand, are not utility system impacts, will not affect rates or bills, and should not be included in rate, bill, and participation analyses.

Example: Assume that a jurisdiction is participating in RGGI, that the estimated price of a RGGI allowance is $12/ton of carbon dioxide, and that there are no other GHG compliance requirements in this jurisdiction. Further assume that the regulators and other stakeholders in this jurisdiction estimate that the total social cost of GHG emissions is $80/ton. In this case, the environmental compliance impact is $12/ton, and the societal environmental impact is $68/ton ($80-$12). (See CPUC 2020, pages 20-23.)

Anticipated Environmental Requirements

A BCA should account for all environmental requirements expected to be in effect over the study period (see RAP 2012; RAP 2013, pages 32-37). This should include requirements that are already established by statutes, regulations, orders, or other directives, even if they have not taken effect yet. If a particular requirement is expected to take effect in three years,

BCAs should account for all environmental requirements expected to be in effect over the study period, including those in place but not yet in effect, and those that are not in place but are likely to be in place during the study period.

4 Societal environmental impacts are sometimes referred to as "environmental externalities." They are also sometimes referred to as "non-embedded" environmental impacts (AESC 2021).

5 Except for the Participant Cost Test, which does not include utility system impacts.

for example, then the implications of that anticipated requirement should be applied in the third year of the BCA study period and beyond.

Similarly, BCAs should also account for environmental requirements that have not yet been established but are reasonably likely to be established within the study period. Environmental regulations often become more stringent over time (see RAP 2013, page 29) and failure to account for such changes will understate the actual environmental compliance costs.

There will inevitably be some uncertainty about anticipated environmental regulations, just as there is uncertainty about most of the impacts discussed in this MTR handbook. Probability techniques can be used to address this uncertainty, as described below.

Uncertain Environmental Requirements: There may be situations where it is not entirely clear whether environmental requirements will be imposed on the electric utility. For example, a state might establish a GHG target, but the target is not a binding mandate, or the target is applied to the entire economy and not explicitly applied to electric utilities. In these situations, stakeholders and regulators should estimate the most likely timing and magnitude of the targets on electric utilities using the best information available. To completely ignore uncertain GHG targets will understate the costs of compliance with them in the BCA. This could result in implementation of fewer DERs, which could ultimately result in higher costs to comply with the targets once they are applied to the electric utilities. Methods for addressing uncertainty and risk in BCAs are discussed in Chapter 10.

Environmental Compliance Impacts Are Sometimes Included in Other Impacts

Some environmental compliance impacts are routinely included as part of the cost of building and operating generation, transmission, and distribution facilities. These include, for example, costs of installing environmental controls such as scrubbers to remove sulfur dioxide and nitrogen oxides emissions, water protection standards, local permitting requirements, and wildlife protection requirements. (See RAP 2013.)

Similarly, some pollutants, such as nitrogen oxides, sulfur oxides, and GHG emissions, are regulated through a cap-and-trade program in some jurisdictions. In these cases, the environmental compliance impacts might already be included in the energy generation cost and therefore should not be included in this category of impacts in a BCA. (See ConEdison 2020, pages 7-8.)

To the extent that environmental compliance impacts are already included in the cost of the relevant energy resource, they should not be included in this category of impacts in a BCA to avoid double-counting of these costs.

3.2.6.b. Methods for Calculating Environmental Compliance Impacts

Figure 17 summarizes the most common methods for estimating environmental compliance impacts, each of which is described in detail below.

Figure 17. Methods for estimating environmental compliance impacts

Impacts of Pollutant Cap-and-Trade Mechanisms	Impacts of GHG Mandates	Methods for Calculating Other Impacts
• Determine the energy saved or generated (in MWh) by the proposed DER • Determine the marginal emission rate (in tons/MWh) using public sources or proxy units • Calculate avoided emissions (in tons) by multiplying DER energy saved or generated by marginal emission rate • Determine the price of the pollutant (in $/ton) allowance using public sources or independent forecasts • Calculate cost of compliance (in $) by multiplying avoided emissions by pollutant allowance price	• GHG Cost Method using marginal abatement costs to calculate the cost of GHG (in $/ton). • GHG Cost Method using social cost of carbon to estimate cost of GHG (in $/ton); only in cases where GHG mandate represents a societal abatement goal • Planning Constraints Method: Design Reference and DER Cases to comply with GHG mandates using the lowest cost resources available in each case	• Pollution Control Equipment Costs: Use publicly available information to determine likely costs for different generation facilities • Fees and Permits Costs:Use publicly available sources for information on fees and permits required for electricity generators • Anticipated Environmental Requirements: Use same methods as for existing requirements, but apply uncertaintly techniques to accommodate uncertainty about timing or details of requirements

Methods for Calculating Impacts of Pollutant Cap-and-Trade Mechanisms

Environmental compliance impacts associated with cap-and-trade mechanisms can be calculated using the steps provided in Table 32. Additional guidance on steps 2 and 4 is provided below the table.

Table 32. Steps to calculate the impacts of pollutant cap-and-trade mechanisms

Step 1	Determine the energy saved or generated (in MWh) by the proposed DER This can be developed using the proposed DERs' load impact profiles (see Chapter 11). Ideally, the energy saved or generated would be estimated on an hourly basis, to reflect the variation across different time periods with different marginal emission rates.
Step 2	Determine the marginal emission rate (in tons/MWh) This step is described further below.
Step 3	Calculate the change in emissions (in tons) Multiply the DER energy saved or generated (from Step 1) by the marginal emission rate (from Step 2).
Step 4	Determine the price of the pollutant allowance (in $/ton) This step is described further below.
Step 5	Calculate the cost of compliance (in $) Multiply the avoided emissions (from Step 3) by the pollutant allowance price (from Step 4).

Step 2. Determine the Marginal Emission Rate

Marginal emission rates should ideally be based on long-run marginal rates, to capture the full impact over the BCA study period (see Section 2.7.2). They should also be based on the electricity generators in the region where the DER will be located because rates can be very different for different regions. Further, marginal emission rates should ideally be estimated on an hourly basis because they can change significantly as the marginal electricity generator changes throughout the day (see Section 2.8).

Several options are available for determining marginal emission rates. It is important to note that the NREL Cambium model is the only tool listed below that provides long-run marginal emission rates. The U.S. EPA AVERT model and eGRID model only provide short-run marginal emissions rates. Therefore, if models providing short-run marginal emission rates are used, then it will be necessary to use other sources or to develop an independent forecast to determine long-run marginal costs.

- Public sources:
    - NREL Cambium model. Cambium is a tool that assembles structured data sets of hourly cost, emission, and operational data for modeled futures of the U.S. electric sector with metrics designed to be useful for long-term decision-making. Cambium was built to expand the metrics reported in NREL's Standard Scenarios—an annually released set of projections of how the U.S. electric sector could evolve across a suite of different potential futures, looking ahead through 2050. (See NREL Cambium.) Cambium is the only model listed here that provides long-run marginal emission rates.
    - U.S. EPA AVERT model. AVERT is an open-access tool offered by the U.S. EPA to estimate the hourly emissions and generation benefits of energy efficiency and renewable energy policies and programs. AVERT allows users to measure displaced emissions of carbon dioxide, sulfur dioxide, nitrogen oxides, particulate matter, ammonia, and volatile organic compounds, as well as avoided generation mitigated by state or multi-state programs. Stakeholders and regulators can also use the tool to identify likely units and regions impacted by different efficiency or renewable energy programs. The tool tracks each fossil unit's generation, heat input, and emissions. It is able to identify likely changes in regional emissions when units are retired, replaced, or retrofitted with pollution controls. AVERT uses public data reported to the U.S. EPA by power plants in the United States. (See U.S. EPA AVERT.)
    - U.S. EPA eGRID model. The Emissions & Generation Resource Integrated Database is a comprehensive source of data from EPA's Clean Air Markets Division on the environmental characteristics of almost all electric power generated in the United States. The data includes emissions, emission rates, generation, heat input, resource mix, and many other attributes. eGRID is typically used for GHG registries and inventories, carbon footprints, consumer information disclosure, emission inventories and standards, power market changes, and avoided emission estimates. (See U.S. EPA 2021 eGrid.)
    - Other tools. See U.S. EPA 2018, pages 4-42 through 4-56, for descriptions and links to a variety of tools to estimate emissions reductions from power plants.
    - ISOs. Some ISOs and RTOs publish marginal emission rates for their electricity system. Examples include ISO-NE 2022; NYISO 2021.
    - AESC 2021. This report includes marginal emission rates for carbon dioxide and nitrogen oxides for electric generators and for non-electric fuels in New England (see AESC 2021, pages 364-368).

- Proxy units: Proxy power plants can be used to create simplistic estimates of marginal emission rates. For example, in a region where natural gas combined cycle power plants are on the margin most of the time, then the emission rates from these power plants can be a rough approximation of system-wide marginal emission rates (see NREL 2014 DPV). The main advantage of this method is that it is simple to implement. However, the U.S. EPA AVERT model is also relatively simple to use and provides more accurate results.

Step 4. Determine the Price of the Pollutant Allowance

Several options are available for forecasting pollutant allowance prices:

- Public sources:
    - Some ISOs and RTOs publish allowance price forecasts (see CPUC 2020, page 21).
    - For RGGI price forecasts, see AESC 2021, pages 105-106.
- Independent forecasts: Forecasts of pollutant allowance prices can be made by assuming a simple growth rate applied to current prices (AESC 2021 uses this approach to forecast sulfur dioxide allowance prices, page 110). Alternatively, independent forecasts can be made by comparing the demand and supply for allowances over time and making assumptions about how prices will increase as demand exceeds supply.

Methods for Calculating Impacts of GHG Mandates

Option 1: GHG Cost Method

Environmental compliance impacts associated with GHG mandates can be calculated using the steps provided in Table 35. These are the same steps used to calculate the impacts of pollutant cap-and-trade mechanisms presented above in Table 32, except for Step 4 where the cost of GHG emissions (in $/ton) is applied instead of the pollutant allowance price. The cost of GHG can be developed using a marginal abatement cost (MAC) or a social cost of carbon (SCC) method, described further below.

Table 33. Steps to calculate the impacts of GHG mandates

Step 1	Determine the energy saved or generated (in MWh) by the proposed DER This can be developed using the proposed DERs' load impact profiles (see Chapter 11). Ideally, the energy saved or generated would be estimated on an hourly basis, to reflect the variation across different time periods with different marginal emission rates.
Step 2	Determine the marginal emission rate (in tons/MWh) This step is described above as Step 2 for calculating impacts of pollutant cap-and-trade mechanisms.
Step 3	Calculate the change in GHG emissions (in tons) Multiply the DER energy saved or generated (from Step 1) by the marginal emission rate (from Step 2).
Step 4	Determine the cost of GHG emissions (in $/ton) Apply either an MAC or an SCC (where appropriate). This step is described further below.
Step 5	Calculate the cost of compliance (in $) Multiply the avoided emissions (from Step 3) by the pollutant allowance price (from Step 4).

Option 1A. Marginal Abatement Cost Method

The cost of curtailing GHG emissions to meet a certain GHG mandate can be estimated by identifying the carbon abatement option that is most likely to be the *marginal* option for meeting that mandate. The marginal abatement option is determined by ranking all the potential abatement options from lowest to highest cost (in $/ton of GHG abated) and identifying the last, i.e., marginal, abatement option needed to reduce GHG emissions to a particular level specified.

A marginal abatement cost curve is a way to identify the marginal abatement option. An MAC curve rank-orders a set of resources in terms of their cost-effectiveness in abating GHG emissions. These curves compile all the relevant abatement options in a step function format to allow for prioritization of options based on cost-effectiveness.

Section 7.1.2 provides guidance on how to develop an MAC curve, and Figure 34 in that section presents an example MAC curve. Each block in the curve represents a GHG abatement option, which in this case includes different DER options that can reduce GHG emissions from electricity generation. The width of each block indicates the magnitude of emissions that can be abated by that DER (in tons). The height of each block indicates the cost of each option, in *net levelized terms* (in $/ton).

The *net levelized cost* is equal to the levelized cost of the abatement option, minus all the levelized benefits of the option except for the GHG benefits. In this way, the curve indicates the GHG abatement cost of each abatement option, beyond all the other costs and benefits of that option. Presenting the net levelized costs in this way allows for straightforward comparison of many different types of abatement options from many different sectors.

For the purposes of estimating GHG *compliance* costs, the target level of GHG emissions should be set at the specific level of the relevant GHG mandate in the jurisdiction (e.g., reduction of GHGs to 50 percent of 1990 emissions by 2030). For the purposes of estimating *societal* GHG impacts, the target level of GHG emissions should be set at a level that reflects a *societal* abatement goal (e.g., net zero GHG emissions by 2050). Guidance on estimating societal GHG impacts is provided in Section 7.1.2

The advantage of the marginal abatement cost method is that it can be applied without relying upon production cost or capacity expansion models. The disadvantage is that it can be challenging and resource-intensive to develop a marginal abatement cost curve for the jurisdiction of interest.

Option 1B: Social Cost of Carbon Method

The SCC method represents another way to estimate the cost of carbon in terms of $/ton. It uses the "damage-based" approach to estimate this cost, instead of the "abatement-based" approach of the MAC. The SCC is based on the dollar value of the net cost to society from adding a ton of GHG to the atmosphere in a particular year. Costs include the net impacts to agricultural productivity, human health effects, property damage from flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of impacts to ecosystems (see U.S. IWG 2021).

Starting in 2008, U.S. federal agencies began regularly estimating the SCC, calculated by an interagency working group (IWG) of experts. Since 2016, the IWG has also estimated the social cost of methane and nitrous oxides. The IWG published an updated set of values for all three types of GHGs in 2021 (see U.S. IWG 2021).

The SCC method can be used to estimate the cost of complying with a GHG mandate only in those jurisdictions that have a mandate to achieve a *societal* abatement goal, e.g., net zero GHG emissions by 2050. Jurisdictions that have a GHG mandate that is less stringent than this societal abatement goal should not use the SCC method. Instead, they should use the MAC method, where the marginal abatement option is based upon the specific GHG abatement goal of the jurisdiction.

Comparison of the Social Cost of Carbon and the Marginal Abatement Cost Methods

Section 7.1.2 provides a comparison of the MAC and SCC methods for estimating either environmental compliance costs or societal GHG impacts. This comparison is summarized in Table 34.

Table 34. Comparison of societal cost of carbon and marginal abatement cost methods

Method	Description	Applications	Advantages	Disadvantages
Social Cost of Carbon	Based on future global damage costs from climate change	1. For determining the total social cost of GHG emissions 2. For determining the cost of compliance with GHG mandates that require meeting a societal GHG goal, e.g., net zero emissions by 2050	• Values are readily available • Values are credible because they were developed and vetted by global experts and federal agencies • Can be applied to emissions from any sector • Does not require a specific carbon reduction target	• Involves considerable uncertainty and debate about future damage costs • Value is extremely sensitive to the discount rate chosen and complex modeling assumptions • Can only be used to determine total social cost of GHG emissions
Marginal Abatement Cost	Based on cost of technologies and other options that can be used to abate GHG emissions to a desired level in the jurisdiction of interest	1. For determining the total social cost of GHG emissions, if a societal GHG goal is used, e.g., net zero emissions by 2050 2. For determining the cost of complying with specific GHG targets	• Well-suited for determining the cost of compliance with GHG targets that are less stringent than a societal GHG goal • Based on known technologies with known costs relevant to the jurisdiction • Reveals the actual costs that might need to be incurred to meet GHG target	• Requires concrete emission abatement targets • Values not easily available; estimates are complex and resource-intensive • Ideally requires analysis for multiple sectors (electric grid, building, transportation, industry)

Option 2: Planning Constraints Method

The most accurate approach for estimating the cost of complying with GHG mandates is to use those mandates as constraints in the resource plans that are created to estimate avoided costs. In other words, the Reference Case and the DER Case (and any sensitivities) should be designed to comply with the GHG mandate using the lowest cost resources available in each case. The Reference Case will have to rely upon a set of clean energy options that does not include new DERs, while the DER Case may not need as many other clean energy options because of the GHG emission reductions available from the DERs.

The difference in costs between the Reference Case and the DER Case will represent the avoided costs of the system, including the avoided costs of achieving the GHG mandates. In other words, the avoided costs of achieving the GHG mandates will not be identified separately from the other avoided costs. If a separate estimate of the avoided costs of the GHG mandate is desired, then one could do a sensitivity analysis comparing a hypothetical Reference Case that does not meet the GHG mandate with the Reference Case that does meet the GHG mandate. The difference in costs between these two cases will indicate the avoided cost of compliance with the mandate, in the absence of the new DERs.

> The most accurate approach for estimating the cost of complying with GHG mandates is to use those mandates as constraints in the resource plans that are created to estimate avoided costs.

The advantage of this method is that it is the most accurate way to identify the incremental cost of complying with the GHG mandate, because it is based upon a least-cost modeling of all the GHG abatement options. The disadvantage of this method is that it can be labor intensive, especially if production cost or capacity expansion models are used for analyzing the Reference Case and the DER Case.

Methods for Calculating Other Impacts

Methods for Calculating Pollution Control Equipment Costs

For situations where pollution control equipment costs are not accounted for in the other estimates of avoided costs, several sources of publicly available information can be used to determine what these costs are likely to be for different generation facilities (see U.S. EIA 2020; Synapse 2021 RI).

The costs of pollution control equipment should be put in terms of revenue requirements for the purpose of creating inputs to a BCA. For capital costs, this requires amortizing the costs over the book life of the asset, and estimating the annual depreciation, equity, debt, and taxes associated with those costs. Non-capital costs, such as fuel and O&M costs, are typically recovered from customers on a pass-through basis, and therefore the revenue requirements for them will be the same as the annual costs.

Methods for Calculating Fees and Permits Costs

Information on fees and permits required for electricity generators can be obtained from several publicly available sources (see NCAA 2018; NY DEC 2021; RAP 2013, page 32; and U.S. EPA 2021 NPDES).

Methods for Calculating Anticipated Environmental Requirements

In general, anticipated environmental requirements can be estimated with the same methods as existing requirements. The main difference is that there might be some uncertainty about the timing or the details of the requirements. In these cases, uncertainty techniques can be applied to determine the most likely impacts (see RAP 2013, pages 32-33). For example, if the likelihood of the promulgation of a future environmental regulation is 70 percent, then the environmental compliance cost for that regulation can be multiplied by 70 percent.

3.2.6.c. Resources for Calculating Environmental Compliance Impacts

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3.3. Transmission Impacts

3.3.1. Transmission Capacity

3.3.1.a. Definition

Transmission capacity refers to the availability of the electric transmission system to transport electricity in a safe and reliable manner. In areas with insufficient transmission capacity available to support transmission of lowest-cost electricity, there will be transmission congestion costs due to the need to utilize higher-cost generation to avoid the transmission constraint.

A DER's impact on transmission capacity depends on its load impact profile during the times coincident with the transmission peaks. If a DER increases load at the time of the transmission system peak, it will result in added costs. Alternatively, if a DER reduces load at the time of the transmission system peak, it will result in reduced costs.

DERs may reduce transmission capacity costs in two ways:

- DERs may passively defer needed transmission capacity investments if their operation for other purposes (e.g., host customer bill management) results in lower load at the same time the transmission facilities are at their peak. In these instances, the DERs may be attributed with a system-wide average for the transmission capacity benefit provided.
- DERs may actively defer transmission capacity needs as part of a geographically targeted non-wires alternative (NWA). The value of active deferrals is typically based on the actual deferral value of the avoided transmission project (i.e., the costs avoided if the wires investment is deferred for a certain number of years). There is often a minimum cost threshold for transmission projects to be considered for an NWA; therefore, the value of active deferrals is typically higher than that of passive deferrals.

Some ISOs/RTOs allow for wholesale market participants to trade fixed transmission rights to help them manage transmission congestion costs. Some DERs might be able to create benefits by reducing transmission congestion and costs of fixed transmission rights. Costs of fixed transmission rights are typically included in wholesale energy market prices and therefore may not need to be included as a separate impact.

3.3.1.b. Methods for Calculating System Average Transmission Impacts

Figure 18 summarizes the most common methods for calculating system average transmission impacts, each of which is described in detail below.

Figure 18. Methods for calculating system average transmission impacts

Ratio of Cost to Load Growth Method	Cost of Service Method	Public and Proprietary Sources
• Select a time period for analysis • Determine actual or expected relevant growth in peak demand over the specified period • Determine load-related transmission investments incurred over that same period to meet load growth • Divide transmission investments by transmission load growth to determine cost of transmission to meet load growth • Estimate annual capital by multiplying total capital costs by a real levelized carrying charge	• Determine capacity impact of DERs • Determine transmission peak impact of the proposed DERs • Determine marginal transmission cost • Determine marginal transmission cost by multiplying change in peak load by marginal transmission cost • Estimate annual capital costs by multiplying total capital costs from third step by real levelized carrying charge	• Publicly available: Use transmission costs published by RTOs and ISOs to estimate avoided wholesale transmission costs • Proprietary: Develop transmission capacity costs using proprietary transmission loss data sources

Option 1: Ratio of Cost to Load Growth

This method calculates the marginal transmission costs associated with load growth. Ideally this method should be based on a combination of historical and forecasted data. However, it is possible to look at historical only or projected only.

This method involves the steps in Table 35.

Table 35. Steps to calculate the marginal transmission costs associated with load growth

Step 1	Select a time period for the analysis Longer time periods are likely to better capture trends in costs and loads. Conversely, longer time periods might include transmission conditions that become less relevant over time.
Step 2	Determine the actual (historical) or expected (projected) relevant growth in peak demand Estimate this in kW over the specified period.
Step 3	Determine the load-related transmission investments (in $) These would be incurred over that same period to meet that load growth.[6] Common investments typically defined as load growth-related include (see AESC 2021, Chapter 10, pg. 243): • Most new transmission lines and substations and additional transformers at existing substations; • Additional feeders and line transformers in areas with existing service; • Reconductoring of lines to increase capacity; • Increasing the voltage of transmission or distribution lines; and • Conversion of single-phase feeder branches to two-phase or three-phase operation. If the investment data used for this step is not inclusive of the O&M costs for the transmission equipment, these costs should be added. O&M costs for additional substations and transmission lines have their own accounts in FERC Form 1.
Step 4	Divide the transmission investments (from Step 3) by the transmission load growth (from Step 2) This will determine the cost of transmission to meet load growth (in $/kW).
Step 5	Estimate the annual capital costs (in $/kW-year) Multiply the total capital costs (in $/kW) from Step 4 by a real levelized carrying charge. The carrying charge should reflect the utility's cost of capital, income taxes, property taxes, insurance costs, and O&M expenses.

For more information see AESC 2021, Chapter 10.

Key Data Sources for Calculating System Average Transmission Impacts

Transmission Investments

- If utility-specific data is not available, FERC Form 1 is filed annually by major utilities and contains transmission costs, referred to as "Transmission Plant," and transmission O&M costs (see FERC Form 1).
- Regional transmission costs are typically available from RTOs.

6 It is important that the actual historical loads and load forecast include the impacts of the proposed DERs, so it aligns with the historical and forecasted investments. Ideally, a no-DER analysis would be performed but it is difficult to determine what historical investments would have been needed in the absence of the DER programs.

Carrying Charge

- Inputs required for calculating the real levelized carrying charge in Step 5 can often be found within utility marginal cost of service studies and in utility FERC Form 1 filings.

Escalation Rate

- When projecting transmission costs into the future, the Transmission Plant Cost Index from the Handy Whitman Index can be used. There is a fee associated with this index (see Handy Whitman).

Table 36 shows examples of states that use the ratio of cost to load growth method to estimate transmission capacity impacts.

Table 36. State examples using ratio of cost to load growth method to estimate transmission capacity impacts

State	Summary
Maine	Avoided transmission costs are based on the long-term ratio of transmission savings per kW of avoided growth. Peak load forecasts and planned transmission capital additions related to load growth are based on utility data. The costs are multiplied by a real levelized carrying charge and an avoided O&M allowance is applied. (See AESC 2021, pgs. 260-261.)
California	Uses a Discounted Total Investment Method (DTIM) to calculate the unit cost of transmission capacity by estimating the present value of peak-demand driven transmission investments divided by peak demand growth. A real economic carrying charge is then applied to this value, as well as other factors such as administrative and general costs and O&M costs. One unique method to California is that it allocates the annual transmission avoided capacity costs to hours of the year using a peak capacity allocation factor (PCAF) method to reflect the time-varying need for transmission capacity. The PCAF method allocates the avoided capacity costs to the hours when transmission is most likely to be constrained and therefore require upgrades. (See CPUC 2020, pg. 37-47.)
Minnesota	Minnesota uses a variation of Ratio of Cost to Load Growth method referred to as the Discrete Approach. This method is unique in that it examines a counterfactual with and without the utility energy efficiency programs. This method is a forecast-only approach where load growth projections and associated transmission investments are estimated with and without the impact of utility energy efficiency plans. The difference between the two is divided by the annual load reductions from energy efficiency in kW/year to obtain the $/kW-year estimate of avoided transmission. (See Xcel, et al. 2017 and MN DOC 2017.)

Advantages and Disadvantages of the Ratio of Cost to Load Growth Method

The primary advantages of this method include its relatively simple approach that relies on publicly available information from FERC Form 1 and the ability to use a long timeframe to address lumpiness of distribution investments. The primary disadvantages are that it can be difficult to determine which transmission system investments are related to load growth and it does not work well in areas with low or negative load-growth forecasts. Load forecast and capital investment schedules may also be proprietary to the relevant utility.

Option 2: Cost of Service Method

This method relies upon recent cost of service studies to identify marginal transmission costs. It involves the steps shown in Table 37 (see ConEdison 2020, pgs. 19-20).

Table 37. Steps to calculate transmission capacity impacts using the cost of service method

Step 1	Determine the capacity impact (in kW) of the proposed DERs This can be determined using the proposed DERs' load impact profiles (see Chapter 11). Ideally, the impact would be developed on an hourly basis to reflect the variation across different time periods.
Step 2	Determine the transmission peak impact of the proposed DERs (in kW) This can be determined by mapping the hours in which peak transmission load occurs to the DERs' load impact profile.
Step 3	Determine the marginal transmission cost (in $) This information can be obtained from the relevant utility's cost of service study filed in the most recent rate case.
Step 4	Determine the marginal transmission cost (in $/kW) Multiply the change in peak load (from Step 2) by the marginal transmission cost (from Step 3).
Step 5	Estimate the annual capital costs (in $/kW-year) Multiply the total capital costs (in $/kW) from Step 3 by a real levelized carrying charge. The carrying charge should reflect the utility's cost of capital, income taxes, property taxes, insurance costs, and operation and maintenance expenses. This data is also often available as part of utility marginal cost of service studies.

The states in Table 38 below demonstrate use of the cost of service method to estimate transmission capacity impacts.

Table 38. State examples using cost of service method to estimate transmission capacity impacts

State	Summary
PacifiCorp (Oregon, Washington, Idaho, California, Wyoming, Utah)	Uses a cost of service study to derive the estimates. Growth-related transmission investment over the subsequent five years is divided by the forecasted change in peak over the same period and this value is annualized. (See Mendota Group 2014 pgs. 8-9.)
Nevada Energy	Uses a marginal cost study associated with recent rate case to determine its avoided T&D costs. (See Mendota Group 2014 pgs. 8-9.)
New York	The New York BCA Handbook includes a methodology for calculating avoided transmission capacity infrastructure and related O&M costs. The system-average costs can be based on marginal cost of service studies. This method accounts for the fact that a portion of avoided transmission capacity is already included in LBMP prices used in the calculation of avoided energy generation impacts. (See ConEdison 2020, pgs. 19-21.)

Option 3: Publicly Available Transmission Costs Forecasts and Proprietary Tools

Publicly available forecasts of transmission costs published by RTOs and ISOs can be used to estimate wholesale transmission impacts.

For states within PJM, the Network Integration Transmission Service (NITS) Rate, as measured in dollars/KW-year, can be used to estimate the direct benefits of avoided wholesale transmission costs in PJM. This method is used in New Jersey (see NJ BPU 2020; PJM 2021).

Table 39 describes how two states use publicly available transmission costs forecasts to estimate transmission capacity impacts.

Table 39. State examples using publicly available transmission costs forecasts to estimate transmission capacity impacts

State	Summary
New Jersey	New Jersey Cost Test framework prescribes using the most recent NITS Rate as applicable to individual utility service territories. (See NJ BPU 2020.)
New Mexico	Southwest Public Service Company used the Southwest Power Pool 10-year integrated transmission plan to calculate the avoided cost of transmission. (See ACEEE 2015.)

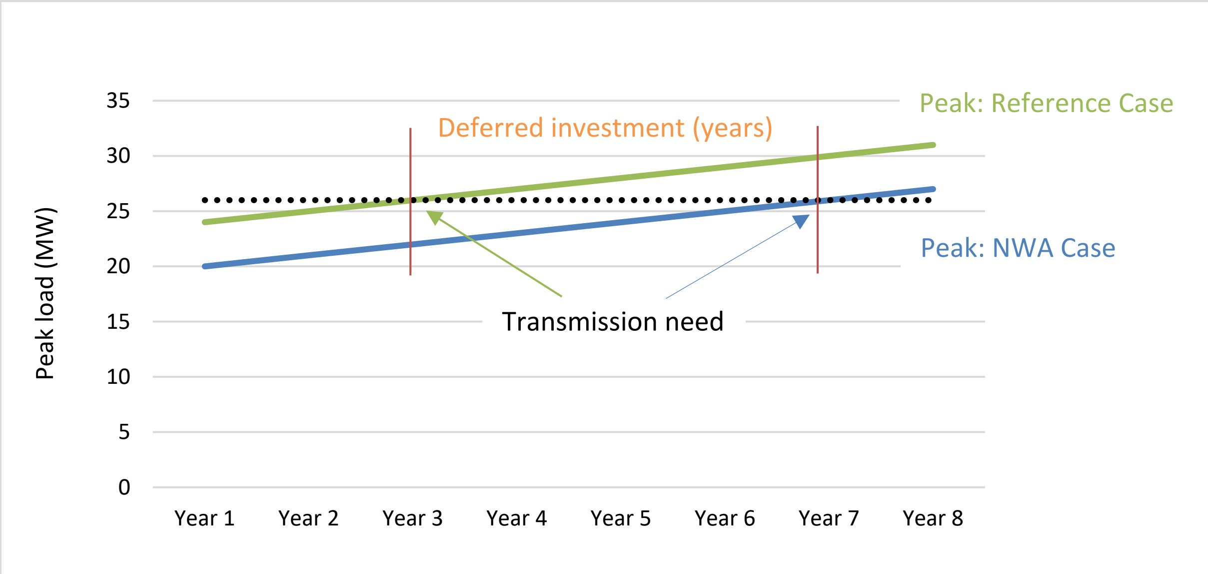
Alternatively, proprietary tools can be used to calculate transmission capacity impacts. Examples of transmission loss data sources include the following (see EPA 2018, pg. 3-56):

- GridLAB-D: Developed by the U.S. Department of Energy's Pacific Northwest National Laboratory, this is a power distribution system simulation and analysis tool to assist utilities in analyzing the impact of new end-use energy technologies, DERs, distribution automation, and retail markets on the electric distribution system. www.gridlabd.org/
- OpenDSS: Designed to simulate electric utility power distribution systems, this tool supports analyses of future increases in smart grid, grid modernization, and renewable energy technology. smartgrid.epri.com/SimulationTool.aspx
- Power Transmission System Planning Software (PSS®E): PSSE offers probabilistic analyses and dynamics modeling capabilities for transmission planning and operations. https://new.siemens.com/global/en/products/energy/energy-automation-and-smart-grid/pss-software/pss-e.html
- PowerWorld Simulator: PowerWorld Corporation offers an interactive power systems simulation package designed to simulate high-voltage power systems operation on a variable timeframe. www.powerworld.com/products/simulator/overview

3.3.1.c. Method for Calculating Locational Transmission Capacity Impacts

Some DERs can help to defer or avoid investments on specific new transmission facilities, e.g., through NWA or geo-targeted DERs. Figure 19 shows how an NWA that reduces peak load could defer a transmission upgrade. In the example below, a business-as-usual system load increase would require a transmission upgrade by Year 15. However, if the NWA can reduce the peak load on the system as shown by the blue line, a transmission upgrade would not be required until Year 35.

Figure 19. Transmission upgrade deferment with NWA



Note: Values are meant to be illustrative and do not represent a real project or transmission system.

Project Deferral Method

Some DERs can help to defer or avoid investments in specific new transmission facilities, e.g., through NWA or geo-targeted DERs. In these cases, the transmission capacity benefits can be determined by analyzing the specific costs to be avoided, using the steps in Table 40.

Table 40. Steps to calculate transmission capacity impacts using the project deferral method

Step 1	Determine the capacity impact (in kW) of the proposed DERs that will be used to defer the transmission facilities: This can be determined using the proposed DERs' load impact profiles (see Chapter 11). Ideally, the impact would be developed on an hourly basis, to ensure there is an accurate match to the transmission peak hours.
Step 2	Determine the original date of installation of the new transmission facilities
Step 3	Determine the expected cost of the new transmission facilities (in $): Assume they are installed at the original date of installation (from Step 2).
Step 4	Determine the number of years that the new transmission facilities might be deferred by the DER: In some cases, this might be only a year or two; in others it might be indefinitely.
Step 5	Calculate the expected cost of the new transmission facilities (in $): Assume they are installed at the later date (from Step 4).

Step 6	**Calculate the difference in costs:** This would be the difference (in $) between those of the original date (from Step 2) and those of the later date (from Step 4).
Step 7	**Calculate the total avoided transmission cost (in $/kW):** Divide the difference in costs (from Step 5) by the capacity avoided by the DER (from Step 1).
Step 8	**Estimate the annual capital costs (in $/kW-year):** Multiply the total avoided transmission costs (in $/kW) from Step 7 by a real levelized carrying charge. The carrying charge should reflect the utility's cost of capital, income taxes, property taxes, insurance costs, and O&M expenses. This data is also often available as part of utility marginal cost of service studies.

The state of Minnesota demonstrates use of the project deferral method, as shown in Table 41 below.

Table 41. State example using the project deferral method to estimate transmission capacity impacts

State	Summary
Minnesota	A recent evaluation of the Minnesota NWA pilot calculated the avoided transmission values using an approach similar to the project deferral method. First the full capital cost is assigned to a proposed upgrade to the transmission system within a project year and the net present value (NPV) of that expenditure is calculated. The deferral value, or avoided capacity cost, is the reduction in NPV if the project is extended by one or more years. (See MN CEE 2021, pg. 11 and Xcel et al. 2017, pgs. 4-15.)

3.3.1.d. Resources for Calculating Transmission Capacity Impacts

American Council for an Energy Efficient Economy. 2015. (ACEEE 2015 System Benefits). Everyone Benefits: Practices and Recommendations for Utility System Benefits of Energy Efficiency. Brendon Baatz. June.

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3.3.2. Transmission System Losses

3.3.2.a. Definition

A portion of all electricity produced at electric generation facilities is lost as it travels across transmission lines. Line losses grow exponentially with higher levels of load, and as such it is important that calculations account for marginal loss rates when determining this impact.

To the extent DERs reduce electricity end-use consumption, they will help reduce electricity transmission and thus reduce transmission line losses. Alternatively, to the extent that DERs increase electricity end-use consumption (through electrification, storage, or electric vehicle charging) they will increase transmission and thus increase transmission losses. The magnitude of the impact will depend on the amount of transmission-level load at the time of the DER's operation.

Transmission losses are sometimes included in wholesale electricity prices in restructured markets. Capacity expansion models and other modeling tools used may already account for transmission losses. Care must be taken to avoid double-counting this impact.

3.3.2.b. Methods for Calculating Transmission System Loss Impacts

This MTR handbook outlines two methods for estimating impacts related to transmission system loss, summarized in Figure 20.

Figure 20. Methods for estimating transmission system loss impacts

Market Data Method	Consumption-Based Method
• Obtain the average loss rate or loss factor from published market data • Convert the average loss factor to a marginal loss factor (according to either energy or peak demand)	• Calculate transmission loss factor using data from U.S. EIA's Annual Energy Outlook

Option 1: Market Data Method

This method, outlined in Table 42, can be used to determine transmission losses for annual energy and peak demand.

Table 42. Steps to determine transmission losses using the market data method

Step 1	**Obtain the average loss rate or loss factor from published market data** The average loss rate should be obtained for both energy and peak demand. This information is sometimes available from RTOs and ISOs (see PJM 2007).
Step 2	**Convert the average loss factor to a marginal loss factor** This step is different depending on whether the marginal loss factor is being calculated for energy or peak demand. Energy: Marginal losses on a line are typically 1.5 times the average loss on the line at that moment. The marginal rate can therefore be estimated by multiplying the average rate by 1.5. (See RAP 2011.) Peak Demand: System utilization rates are higher at peak hours and therefore the factor for converting average to marginal loss factors should be higher than that used for annual energy. The 2021 AESC estimates a factor of 2.0 for this conversion as an appropriate estimate. Therefore, the marginal rate can be estimated by multiplying the average rate by 2.0. (See AESC 2021, pg. 92-93.)

Table 43 shows several examples of states using the market data method to estimate transmission system losses.

Table 43. State examples using the market data method to estimate transmission system losses

State	Summary
New England states	Uses average factors from ISO-NE and converts to a marginal value, per 2011 RAP paper. (See AESC 2021, pg. 332.)
Washington D.C.	Uses average loss rate from PJM and converts to a marginal rate, per 2011 RAP paper. (See Synapse 2017, pgs 130-131.)
Maine	Value of solar study calculates losses on an hourly basis for the study period reflecting marginal losses. The marginal avoided losses in each hour reflect the difference between a case in which the PV resource is operating and a case in which the PV resource is not operating. The study specifies three different types of losses to be calculated: annual avoided energy losses, effective load-carrying capability (ELCC) losses, and peak load reduction (PLR) losses. The avoided annual energy losses represent the avoided T&D losses for all hours in the analysis period; the ELCC losses represent the avoided T&D losses during the 100 peak hours; and the PLR losses represent avoided distribution losses during peak hours. Each of these loss values must be calculated twice each, first including the effects of avoided marginal losses, and then recalculating them assuming no losses. (See Clean Power Research 2015 pgs. 26-27.)

Option 2: Consumption-Based Method

This method calculates a transmission loss factor throughout the generation, transmission, and distribution process (see U.S. EPA 2018).

The formula is:

$$\frac{(Net\ Generation\ to\ the\ Electric\ Grid + Net\ Imports - Total\ Electricity\ Sales)}{Total\ Electricity\ Sales}$$

The data needed for this calculation can be obtained from Table 8 of the U.S. EIA *Annual Energy Outlook* (U.S. EIA AEO 2022).

Key Data Sources for Transmission System Losses

- Utilities often collect average annual energy loss data by voltage level (as a percentage of total sales at that level).
- RTO and ISO websites.
- Resource planning and released regulatory proceedings.

3.3.2.c. Resources for Calculating Transmission Loss Impacts

Avoided Energy Supply Components Study Group. 2021. (AESC 2021). *Avoided Energy Supply Components in New England: 2021 Report*. Prepared by Synapse Energy Economics, Resource Insight, Les Demans Consulting, Northside Energy, Sustainable Energy Advantage.

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3.4. Distribution Impacts

3.4.1. Distribution Capacity

3.4.1.a. Definition

Distribution capacity refers to substation and distribution line infrastructure necessary to meet customer electric demand, and as such the impact will depend on the cost associated with the specific type of distribution infrastructure being affected. If peak demand exceeds distribution capacity, it will require investments to increase distribution capacity to a level that preserves safety and reliability. The net effect of DERs on distribution capacity depends on their load impact profiles during the distribution system peaks.

DERs can either actively or passively help defer or eliminate the cost of needed investments by reducing net load during peak hours. With respect to passive benefits, a DER may have the effect of reducing net load despite operating for some other purpose (e.g., host customer bill management). In terms of active deferrals, a utility may incentivize DERs through pricing, programs, or procurements to provide distribution capacity benefits.

Alternatively, DERs might increase distribution capacity costs if the local distribution system does not have sufficient hosting capacity (i.e., if a given feeder cannot accommodate more DERs without impacting system operation under existing control and infrastructure configurations). For example, if a DER consumes electricity from the grid during times of the distribution peak load or injects electricity onto the grid during times of minimum load (and therefore creates voltage issues) it would have the effect of creating a cost to invest in the necessary distribution infrastructure to avoid these issues.

Distribution capacity impacts can be calculated for the electric system on average or on a location-specific basis.

3.4.1.b. Methods for Calculating System Average Impacts

Figure 21 summarizes two methods for calculating system average DER impacts.

Figure 21. Methods for calculating system average impacts

Ratio of Cost to Load Growth Method

- Select time period for analysis
- Determine actual or forecasted load growth for analysis period using weather-normalized peak loads
- Estimate load-related distribution investments in dollars to meet load growth
- Divide costs identified in third step by load growth to calculate cost of load growth
- Estimate annual capital costs by multiplying total capital costs from fourth step by a real levelized carrying charge

Cost of Service Method

- Determine capacity impact of DERs using DERs' load impact profiles
- Determine distribution peak impact of DERs by mapping hours in which peak distribution load occurs to load impact profile
- Determine marginal distribution cost using utility's cost of service study from most recent rate case
- Determine marginal distribution cost by multiplying change in peak load by marginal distribution cost
- Estimate annual capital costs by multiplying total capital by a real levelized carrying charge

Option 1: Ratio of Cost to Load Growth Method

This method calculates the marginal distribution costs associated with load growth. Ideally this method should be based on a combination of historical and forecasted data. However, it is possible to look at historical only or projected only.

This method involves the steps shown in Table 44.

Table 44. Steps to calculate marginal distribution costs related to load growth

Step 1	Select a time period for the analysis This can include historical, prospective, or a combination of both. A longer timeframe (i.e., 15 years of historical and 10 years of forecast data) can address issues of "lumpiness" related to distribution investments.
Step 2	Determine actual or forecasted load growth (MW) for the analysis period Use weather-normalized peak loads.[7]
Step 3	Estimate the load-related distribution investments (dollars) to meet the load growth identified in Step 2 This step matches investments to load growth. It involves the disaggregation of distribution capital investments related to just load growth-related investments that enter service during the time period of the analysis. Common investments typically defined as load growth-related include (see AESC 2021, Chapter 10, pg. 243): • Most new distribution lines and substations and additional transformers at existing substations; • Additional feeders and line transformers in areas with existing service; • Reconductoring of lines to increase capacity; • Increasing the voltage of transmission or distribution lines; and • Conversion of single-phase feeder branches to two-phase or three-phase operation. If the investment data used for this step is not inclusive of the O&M costs for the distribution equipment, these costs should be added. O&M costs for distribution lines have their own accounts in FERC Form 1.
Step 4	Divide the costs identified in Step 3 by the load growth from Step 2 This calculates the cost of load growth in $/MW or $/kW. For utilities experiencing an absence of load growth or small increases in load growth, dividing Step 3 by Step 2 may result in a negative or otherwise meaningless value. To address this issue, the analysis time period can be adjusted so that Steps 2 and 3 rely on historical data from a period with load growth. Another option is to calculate the avoided cost per kW of growth for the fraction of the distribution system that has or is forecasted to experience growth.
Step 5	Estimate the annual capital costs (in $/kW-year) Multiply the total capital costs (in $/kW) from Step 4 by a real levelized carrying charge. The carrying charge should reflect the utility's cost of capital, income taxes, property taxes, insurance costs, and O&M expenses. This data is also often available as part of utility marginal cost of service studies.

For more information on this method see AESC 2021, Chapter 10, pgs. 236-261. For examples of its use, see Table 45 below.

Advantages and Disadvantages of the Ratio of Cost to Load Growth Method

The primary advantages of this method include its relatively simple approach that relies on publicly available information from FERC Form 1 and the ability to use a long timeframe to address lumpiness of distribution investments. The primary disadvantages are that it can be difficult to determine which distribution system investments are related to load growth and it does not work well in areas with low

[7] It is important that the actual historical loads and load forecast include the impacts of the proposed DERs so they align with the historical and forecasted investments. Ideally, a no-DER analysis would be performed but it is difficult to determine what historical investments would have been needed in the absence of the DER programs.

or negative load growth forecasts. Load forecast and capital investment schedules may also be proprietary to the relevant utility.

Table 45. State examples using the ratio of cost to load growth method to estimate distribution capacity impacts

State	Summary
Rhode Island, Massachusetts	National Grid calculates the annualized value of statewide avoided distribution capacity values from company-specific inputs that include historical and projected capital expenditures and peak loads, carrying charges, FERC Form 1 accounting data, and O&M costs. National Grid uses a combination of historical and forecasted values and accounts for operational energy efficiency, PV, and demand response programs. The load forecast used to determine the value of avoided distribution only includes projected PV and continued lifetime energy efficiency savings from prior energy efficiency plans and the current energy efficiency plan; it does not include forecasted savings from future energy efficiency plans. National Grid determines the percentage of the total distribution investments that are load-growth-related but not associated with new business and applies that percentage to the distribution investment forecast. (See AESC 2021, pgs.254-255.)
Iowa, Illinois, South Dakota	For these states, MidAmerican Energy Company uses this method, but only examines one year of data. It uses data from FERC Form 1 to calculate the net costs for the distribution system by taking the original cost of plant less accumulated depreciation. It then obtains load data and generation capability data to approximate the peak demand of the distribution system. It then calculates the average cost to serve existing load for the distribution system by dividing the distribution system's net cost by its peak demand. The resulting $/kW value represents the cost of the distribution system. (See Mendota Group 2014, pg. 7.)
Minnesota	Minnesota uses a variation of Ratio of Cost to Load Growth method referred to as the Discrete Approach. This method is unique in that it examines a counterfactual with and without the utility energy efficiency programs. This method is a forecast-only approach where load growth projections and associated distribution investments are estimated with and without the impact of utility energy efficiency plans. The difference between the two is divided by the annual load reductions from energy efficiency in kW/year to obtain the $/kW-year estimate of avoided distribution. (See Xcel, et al. 2017 and MN DOC 2017)
New York (CHG&E)	Central Hudson Gas & Electric (CHG&E) takes a similar approach to Minnesota and removes future DER installations from the load forecast to construct a counterfactual baseline by which to measure the impacts of additional DERs. CHG&E conducts a probabilistic load forecast to assess the impacts of DERs over a range of possible futures. Once the marginal costs associated with load growth on the distribution system are identified, it applies the economic carrying charge associated with traditional investments to calculate an annual deferral value. (See CHG&E 2018)

Option 2: Cost of Service Method

This method relies upon recent cost of service studies to identify marginal distribution costs. It involves the steps in Table 46.

Table 46. Steps to estimate marginal distribution costs using the cost of service method

Step 1	**Determine the capacity impact (in kW) of the proposed DERs**	
	This can be determined using the proposed DERs' load impact profiles (see Chapter 11). Ideally, the impact would be developed on an hourly basis to ensure there is an accurate match to the distribution peak hours.	
Step 2	**Determine the distribution peak impact of the proposed DERs (in kW)**	
	This can be determined by mapping the hours in which peak distribution load occurs to the DERs' load impact profile.	

Step 3	**Determine the marginal distribution cost (in $)** This information can be obtained from the relevant utility's cost of service study filed in the most recent rate case.
Step 4	**Determine the marginal distribution cost (in $/kW)** Multiply the change in peak load (from Step 1) by the marginal distribution cost (from Step 2).
Step 5	**Estimate the annual capital costs (in $/kW-year)** Multiply the total capital costs (in $/kW) from Step 3 by a real levelized carrying charge. The carrying charge should reflect the utility's cost of capital, income taxes, property taxes, insurance costs, and O&M expenses. This data is also often available as part of utility marginal cost of service studies.

New York State demonstrates the use of the cost of service method to estimate distribution capacity impacts, as shown in Table 47.

Table 47. State example using the cost of service method for estimating distribution capacity impacts

State	Summary
New York (ConEdison)	ConEdison calculates system-average distribution costs based on marginal cost of service studies. It relies on a marginal cost of service study to estimate the potential avoided distribution costs (feeders, distribution transformers, secondary wires). (See ConEdison 2020, pgs. 26-28.)

Additional Methods Used by Some States

The following states use approaches that contain aspects of the above methods but are unique enough to warrant a detailed description.

California

California uses a similar approach to the ratio of cost to load growth method, with several key differences related to the granularity of the assessment and the use of a more detailed assessment of deferrable capacity.

The Avoided Cost Calculator calculates unspecified deferrals, which estimate the near-term, system-wide marginal distribution capacity costs under the No New DER local load or "counterfactual" forecast where new embedded DER are removed from the utility's planning forecast.

The method involves following five steps (see CPUC pgs. 49-51; and CPUC 2019, Attachment A, pg. 11).

Step 1. Calculate the counterfactual forecast for each listed circuit, by removing the circuit-level DER forecast from the circuit-level load.

Step 2. Identify potential new capacity projects for all circuits that exceed the facility rating in any year of the counterfactual forecast.

Step 3. Estimate the percentage of distribution capacity overloads that lead to a deferred distribution upgrade by calculating a system-level quantity for deferred distribution capacity using a ratio between capacity overloads to deferrable capacity overloads. The resulting percentage is a proxy for the percentage of distribution capacity upgrades that can be deferred by DER. This percentage is then multiplied by the number of deferrable projects from Step 2 to determine the subset of counterfactual capacity projects that could potentially be deferred by DER.

Step 4. Calculate the average marginal cost ($/kW-yr) of the deferred distribution upgrades by summing the avoided distribution cost ($/kW-yr) for each project multiplied by its total deficiency over the planning horizon, divided by the total deficiency for all projects.

Step 5. Calculate system-level avoided costs by multiplying the average marginal cost found in Step 4 by the total quantity of deferred capacity by DERs for each circuit. The product is divided by the sum of forecasted level of DERs for all areas to obtain a single, system-level distribution deferral value in $/kW-yr. This value is then converted into a system average marginal cost by applying a Real Economic Carrying Charge (RECC) annualization factor along with general and administration costs and O&M.

Maryland

To calculate avoided distribution costs, Baltimore Gas & Electric takes the following steps. (See Exeter 2014, pg. 31.)

Step 1: Escalate actual capital cost of distribution (below the 230 kV level) over the last 45 years, converted to current-year dollars.

Step 2: Estimate the load-carrying capability of distribution as "the all-time, unrestricted, peak load not normalized for weather" (see Exeter 2014).

Step 3: Apply a "functionality discount factor" of 1.5 to account for the fact that energy efficiency measures as designed are not targeted or controlled to address local feeder constraints.

Step 4: Calculate the avoided distribution costs by taking the capital costs divided by peak load divided by the functionality discount factor, then multiplied by the asset life discount factor.

Key Data Sources for Calculating System-Average Distribution Capacity Impacts

The methods summarized in this section have a similar set of data requirements. These include:

- Peak load forecast: This data is proprietary to utilities. In the absence of peak load forecasts, other data may be substituted. For example, for states in ISO-NE, *Capacity, Energy, Loads, and Transmission Load (CELT) Forecasts* can be used. (See ISO-NE Load Forecast.)
- Distribution investment data: This data is proprietary to utilities.
- O&M costs: If utility-specific data is not available, FERC Form 1 is filed annually by major utilities and contains distribution O&M costs. (See FERC Form 1.)

3.4.1.c. Resources for Calculating System Distribution Capacity Impacts

Avoided Energy Supply Components Study Group. 2021. (AESC 2021). *Avoided Energy Supply Components in New England: 2021 Report*. Prepared by Synapse Energy Economics, Resource Insight, Les Demans Consulting, Northside Energy, Sustainable Energy Advantage.

California Public Utilities Commission. 2020. (CPUC 2020). Distributed Energy Resources Avoided Cost Calculator Documentation for the California Public Utilities Commission. Version 1c. Prepared by Energy and Environmental Economics, Inc. June.

Consolidated Edison Company of New York. 2020. (ConEdison 2020). Electric Benefit Cost Analysis Handbook. Version 3.0.

Guidehouse. 2020. *New Hampshire Locational Value of Distributed Generation Study*. Prepared for the New Hampshire Public Utilities Commission.

ISO New England. n.d. (ISONE Load Forecast). "Load Forecast." iso-ne.com website. https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/

Mendota Group. 2014. *Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments*. Prepared for the Public Service Company of Colorado. October 23.

New Jersey Board of Public Utilities. 2020. (NJ BPU 2020). In the Matter of the Clean Energy Act of 2018 – New Jersey Cost Test. Docket Nos. QO19010040 & QO20060389.

U.S. Environmental Protection Agency. 2018. (U.S. EPA 2018). *Quantifying the Multiple Benefits of Energy Efficiency and Renewable Energy: A Guide for State and Local Governments*. www.epa.gov/statelocalenergy/quantifying-multiple-benefits-energy-efficiency-and-renewable-energy-guide-state.

Xcel Energy, Minnesota Power, Otter Tail Power Company with the Mendota Group, LLC, and Energy & Environmental Economics. 2017. (Xcel et. al. 2017). *Minnesota Transmission and Distribution Avoided Cost Study*. www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={D0549A5D-0000-CE15-BEF1-9B48DB00A554}&documentTitle=20177-134393-01.

3.4.1.d. Methods for Calculating Locational Distribution Capacity Impacts

Some DERs can help to defer or avoid investments on specific new distribution facilities, for instance, through NWA or geo-targeted DERs. States use a variety of methods to calculate locational avoided distribution capacity impacts. The section below provides a summary of a selection of common methods. It also includes a list of data resources for inputs that are common across these methods.

Project Deferral Method

This method is similar to the project deferral method for locational transmission capacity in Section 3.3.1.c. This method uses a utility's distribution system planning process to identify system needs that can be avoided or deferred through the implementation of a DER solution. It uses the present value of avoided traditional utility investments and the needed load reduction to develop locational avoided distribution costs.

This method involves the steps described in Table 48 (see AESC 2021 pgs. 261-267). Table 49 below provides examples of states using the method.

Table 48. Steps to calculating locational distribution capacity impacts using the project deferral method

Step 1	Identify the system need This step identifies the feeder or target areas that require a reduction in load. This step typically comes from a utility's distribution planning process where the utility will identify system contingencies at peak load levels under normal and contingency operations (i.e., 50/50 or 90/10).[8]
Step 2	Identify cost associated with the traditional utility solution Identify the cost of the traditional utility project that would be used to address the distribution system need (i.e., building a new substation, adding a new feeder) identified in Step 1. This step typically relies on either utility budget estimates or cost of service studies.
Step 3	Calculate the deferral value This step determines the benefits of targeted load reductions identified in Step 1. This step involves calculating the present value of the deferred investment in the traditional utility solution. This should reflect the utility's cost of capital, income and property taxes, O&M, and insurance over the life of the equipment.
Step 4	Determine the required load reduction profile (in kW) This is the reduction needed to defer or avoid the traditional utility investment identified in Step 2.
Step 5	Calculate the avoided cost Divide the present value of the deferral value from Step 3 (in $) by the load reduction from Step 4 (in kW) to obtain an avoided cost value in $/kW.

The following inputs are required to conduct this analysis:

- Normal, emergency, and short-term emergency ratings for all facilities on the selected portions of the distribution system—including feeders, power transformers, and circuit breakers—for both summer and winter periods.
- Utility planning criteria (allowable voltage ranges and equipment loadings under normal and contingency events, under both 50/50 and 90/10 weather).
- Current hourly loadings for equipment in the study.
- Forecasted load for each portion of the distribution system in the study, excluding the proposed DERs. (At a minimum, the study would need the forecast in peak demand for each feeder; ideally it would have load profiles).

[8] 90/10 provides the peak for which there is a 10% probability of being exceeded by the actual peak. Similarly, a 50/50 forecast provides the peak for which there is a 50% probability of being exceeded by the actual peak.

Table 49. State examples using the project deferral method to estimate distribution capacity impacts

State	Summary
New Hampshire	The Locational Value of Distributed Generation (LVDG) study recently calculated the avoided cost of localized distribution capacity deferral or avoidance. The study identified needed distribution capacity investments over a 15-year planning horizon and determined where capital investments could potentially be avoided through load reduction. It then estimated the value of potential avoided capacity investments. The last step involved performing an economic analysis to estimate the benefit of capacity avoidance and map representative distributed generation production profiles with distribution system capacity needs. (See Guidehouse 2020.)
Rhode Island	National Grid considers NWAs as part of its distribution planning process for distribution and sub-transmission capital projects and system needs. National Grid develops project-specific distribution capacity values and develops avoided distribution costs based on the avoided wires investment. The company has developed a calculator to develop the net-present value of the deferral value that takes into account the location-specific wires solution expected cost, related O&M costs, depreciation, and revenue requirements over the course of the expected lifetime of a wires solution. (See Narragansett Electric 2020.)
Minnesota	A recent evaluation of the Minnesota NWA pilot calculated the avoided transmission and distribution values using an approach similar to the project deferral method. First the full capital cost is assigned to a proposed upgrade to the distribution system within a project year and the NPV of that expenditure is calculated. The deferral value, or avoided capacity cost, is the reduction in NPV if the project is extended by 1 or more years. (See CEE 2021, pg. 11 and Xcel et al. 2017, pgs. 4-15.)
New York	New York is currently in the process of reviewing its methodology for calculating the value of locational distribution capacity. New York State's Reforming the Energy Vision (NY REV) proceeding began a process to create a Value of Distributed Energy Resources (VDER) to inform compensation of certain DERs based on a value stack. One of the benefits in the value stack is a locational system relief value (LSRV). The LSRV represents the value created within a location on the distribution system based on specific distribution costs that can be offset with DERs. DERs within LSRV zones receive a higher compensation relative to DERs deployed in non-LSRV areas. (See NY PSC 2019.) The values for LSRV have historically come from utility marginal cost of service studies. However, the New York State Public Service Commission's (NY PSC) April 2019 Order initiated Case 19-E-0283, the *Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies*. At the time of this report neither the PSC Staff whitepaper nor the PSC order had been issued. For updates on the proposed methodology, see Case 19-E-0283.

3.4.1.e. Resources for Calculating Locational Distribution Capacity Impacts

Avoided Energy Supply Components Study Group. 2021. (AESC 2021). *Avoided Energy Supply Components in New England: 2021 Report*. Prepared by Synapse Energy Economics, Resource Insight, Les Demans Consulting, Northside Energy, Sustainable Energy Advantage.

California Public Utilities Commission. 2019. (CPUC 2019). Administrative Law Judge's Amended Ruling Requesting Comments on the Energy Division White Paper on Avoided Costs and Locational Granularity of Transmission and Distribution Deferral Values. Docket No. R.14-08-013 et al., A.15-07-005 et al.

Guidehouse. 2020. *New Hampshire Locational Value of Distributed Generation Study*. Prepared for the New Hampshire Public Utilities Commission.

Minnesota Center for Energy and Environment. 2021. (MN CEE 2021). *Non-Wires Alternatives as a Path to Local Clean Energy: Results of a Minnesota Pilot*. www.mncee.org/sites/default/files/report-files/Non-Wires%20Alternatives%20as%20a%20Path%20to%20Local%20Clean%20Energy.pdf

Narragansett Electric. 2020. *2021-2023 System Reliability Procurement Three-Year Plan*. www.ripuc.ri.gov/eventsactions/docket/5080-NGrid-SRP%202021-2023%20Three-Year%20Plan(11-20-2020)V1.pdf.

New York State Public Service Commission. 2019. (NY PSC 2019). Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies. Case No. 19-E-0283.

Xcel Energy, Minnesota Power, Otter Tail Power Company with the Mendota Group, LLC, and Energy & Environmental Economics. 2017. (Xcel et. al. 2017). *Minnesota Transmission and Distribution Avoided Cost Study*. www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={D0549A5D-0000-CE15-BEF1-9B48DB00A554}&documentTitle=20177-134393-01.

3.4.2. Distribution Operations and Maintenance

3.4.2.a. Definition

Utilities must incur O&M expenses to maintain the safe and reliable operation of distribution facilities. This includes maintenance of substations, wires, and poles, as well as repairs and replacements. Some portion of distribution O&M expenses are variable, which means the expense incurred by a utility is a function of the volume of energy transfers through the system.

When DERs reduce electricity consumption, they will typically reduce the energy transfers through distribution facilities. This creates a benefit by reducing variable distribution O&M expenses. Alternatively, when DERs increase electricity consumption, they might increase distribution O&M expenses. DERs that are intermittent generation resources can lead to increased distribution costs due to the need to manage energy flows to maintain voltage and equipment ratings within acceptable limits.

3.4.2.b. Method for Estimating Distribution Operations and Maintenance Impacts

Distribution O&M costs are typically included in estimates of distribution capacity costs, in which case they do not need to be estimated separately.

3.4.3. Distribution System Losses

3.4.3.a. Definition

A portion of all electricity produced at electric generation facilities is lost as it travels across the distribution system to the final point of consumption. This includes losses on the distribution lines and transformers. Line losses expand exponentially as the system experiences higher levels of load, so cost-effectiveness calculations should account for marginal loss rates.

The net effect of a DER's operation on distribution line and transformer energy losses depends on the relative balance between load and net DER output. For example, if the net impact of DERs is a reduction of load at the feeder level, then there can be net reductions in line and transformer energy losses, and vice versa.

It is important to note that capacity expansion models and other modeling tools used may already account for distribution losses. Care must be taken to avoid double counting this impact.

3.4.3.b. Methods for Calculating Distribution System Losses

Option 1: Market Data Method

This method is the same as for calculating transmission loss factors (see Section 3.3.2.b).

Option 2: Consumption-Based Method

This method is the same as for calculating transmission loss factors (see Section 3.3.2.b).

Option 3: Publicly Available Distribution Loss Impacts

The data sources for distribution losses are the same as those for transmission losses (see Section 3.3.2.b).

Option 4: Proprietary Tools

The proprietary tools for distribution losses are the same as those for transmission losses (see Section 3.3.2.b).

3.4.3.c. Resources for Calculating Distribution Loss Impacts

Avoided Energy Supply Components Study Group. 2021. (AESC 2021). *Avoided Energy Supply Components in New England: 2021 Report*. Prepared by Synapse Energy Economics, Resource Insight, Les Demans Consulting, Northside Energy, Sustainable Energy Advantage.

California Public Utilities Commission. 2020. (CPUC 2020). Distributed Energy Resources Avoided Cost Calculator Documentation for the California Public Utilities Commission. Version 1c. Prepared by Energy and Environmental Economics, Inc. June.

Clean Power Research. 2015. *Maine Distributed Solar Valuation Study*. Prepared for the Maine Public Utilities Commission.

Synapse Energy Economics. 2017. (Synapse 2017). *Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting*. Prepared for the Office of the People's Counsel for the District of Columbia.

U.S. Environmental Protection Agency. 2018. (U.S. EPA 2018). *Quantifying the Multiple Benefits of Energy Efficiency and Renewable Energy: A Guide for State and Local Governments*. www.epa.gov/statelocalenergy/quantifying-multiple-benefits-energy-efficiency-and-renewable-energy-guide-state.

3.4.4. Distribution Voltage

3.4.4.a. Definition

Voltage regulation is necessary to ensure reliable and continuous electricity flow across the power grid. Voltage on the distribution system must be maintained within an acceptable range to ensure that both real and reactive power production are matched with demand (see RMI 2015).

DERs can either exacerbate or help address emerging voltage issues on the distribution system. Consequently, it is especially important to apply the DER's load impact profile when estimating this impact.

3.4.4.b. Method for Estimating Distribution Voltage Impacts

Some wholesale electricity markets include voltage regulation as one of the ancillary services offered. In these cases, the price for voltage regulation (in $/MWh) can be used to indicate the benefit of improved voltage regulation or the cost of worsened voltage regulation.

For example, the NY-ISO provides ancillary service prices for voltage regulation in $/MWh on an hourly basis (see NY ISO Pricing). Another resource is the reactive power provisions contained in Schedule 2 of the FERC pro forma open access transmission tariff (See U.S. EPA 2018, pg. 3-33).

3.4.4.c. Resources for Calculating Distribution Voltage Impacts

Federal Energy Regulatory Commission. n.d. (FERC OATT). "Open Access Transmission Tariff (OATT) Reform." ferc.gov website. Schedule 2. www.ferc.gov/power-sales-and-markets/open-access-transmission-tariff-oatt-reform.

New York Independent System Operator. n.d. (NY ISO Pricing). "Pricing Data: Ancillary Services." nyiso.com website. www.nyiso.com/energy-market-operational-data.

U.S. Environmental Protection Agency. 2018. (U.S. EPA 2018). *Quantifying the Multiple Benefits of Energy Efficiency and Renewable Energy: A Guide for State and Local Governments*. www.epa.gov/statelocalenergy/quantifying-multiple-benefits-energy-efficiency-and-renewable-energy-guide-state.

3.5. Electric Utility General Impacts

3.5.1. Financial Incentives Provided by Program Administrator

3.5.1.a. Definition

This impact includes financial incentives provided by the DER program administrator (i.e., utility, or third-party) to DER host customers or other market actors (e.g., retailers, contractors, distributors, manufacturers, integrators, and aggregators) to encourage DER implementation.

Financial incentives may come in various forms, including: incentives or rebates; buy-downs of interest rates for financing a portion of DER costs; payments to support trade ally reporting on sales of DERs, funding or co-funding of marketing of DER equipment by trade allies; and sales bonuses provided to retail or contractor sales staff for selling DER equipment.

Some DERs, such as distributed PV resources, receive incentives through compensation mechanisms in a distributed generation tariff (e.g., net metering, net billing, buy-all/sell-all). These compensation mechanisms are not equivalent to direct financial incentives and should not be included in a BCA as a cost of the DER. Distributed generation tariffs will typically result in lost revenues, which can sometimes lead to cost-shifting, and therefore they should be accounted for in rate, bill, and participation analyses (see NSPM 2020, Section 8.5.1, Section 8.6, and Appendix A).

3.5.1.b. Method for Determining Financial Incentives Impacts

The financial incentives offered to program participants and host customers are typically designed to overcome the market barriers that prevent customers from adopting DERs on their own. They can be based on a variety of factors, including customer surveys (how much is needed to change behavior);

payback periods; results from evaluation, measurement, and verification studies; market studies (percent penetration); or rate classifications (e.g., 100 percent incentives for low-income residences). In addition, the financial incentives offered for a DER will depend upon the jurisdiction, the program administrator, the program design, the DER type, the customer type, and more.

Consequently, this information is best obtained by requesting it from the utility, the DER program administrator, or other stakeholders involved in the development of the DER program. Some energy efficiency and demand response program administrators present information on financial incentives in the prospective energy efficiency plans that they file with regulators to obtain approval of the plans. Some utilities might provide similar plans for programs for other types of DERs.

If information is not readily available from the utility or program administrator, these impacts can sometimes be estimated by using data from comparable programs offered by other utilities or program administrators.

3.5.2. Program Administration Costs

3.5.2.a. Definition

Program administration costs are those incurred by the DER program administrator related to the planning, design, implementation, and evaluation of a DER program or initiative.

These costs may come in a variety of forms, including costs to support utility outreach to trade allies; technical training; other forms of technical support; and marketing, administration, and management of DER programs or portfolios of programs. Administration costs also often include evaluation, measurement, and verification studies to inform either DER program design or retrospective assessment of DER performance.

3.5.2.b. Methods for Calculating Program Administration Costs

DER program administration costs will depend upon the jurisdiction, the program administrator, the program design, the DER type, the customer type, and more. Consequently, this information is best obtained by requesting it from the utility, the DER program administrator, or other stakeholders involved in the development of the DER program.

In some cases, it might be possible to use rough estimates of program administration costs from similar jurisdictions with similar programs. For example, by applying administration costs as a percentage of the total DER program budget to the DER program of interest. This approach, however, should be used with caution because the administration costs can vary depending upon the administrator—even for similar DER programs.

3.5.3. Program Administrator Performance Incentives

3.5.3.a. Definition

In many jurisdictions, DER program administrators (i.e., utilities, or third parties) are offered financial incentives for meeting specific performance metrics related to the success of DER programs. These performance incentives represent a cost associated with the delivery of the DER program.

DER performance incentives can take many forms, including shared savings mechanisms, payments for meeting energy savings targets, payments for meeting capacity savings targets, or combinations of the above. Performance incentives can take the form of rewards, or penalties, or both.

Energy efficiency and demand response programs are frequently supported by utility performance incentives, while it is much less common for such incentives to be applied to other types of DER programs.

3.5.3.b. Methods for Calculating Performance Incentives Impacts

Performance incentives are typically set by legislation or regulators and are usually unique to a jurisdiction, state, or utility. They can sometimes be obtained from relevant legislation, regulations, or commission orders. They might also be available from commission dockets used to establish performance incentive mechanisms for a variety of utility services.

Otherwise, this information can be obtained by requesting it from the utility, the DER program administrator, or other stakeholders involved in the development of the utility performance incentive.

Whether a utility or program administrator meets its performance goals will not be known until the end of the program year or planning cycle. Therefore, an assumption will need to be made about the magnitude of incentive to include in the DER BCA. The magnitude chosen should represent the most likely outcome, which could for example be based on (a) historical performance levels, (b) target performance levels, or (c) a mid-point between the lower and upper bounds of the potential incentive.

3.5.4. Credit and Collection Costs

3.5.4.a. Definition

This includes costs associated with customers who are deficient on energy bill payments, including notices and support provided to customers in arrears, terminations, disconnections, reconnections, carrying costs associated with arrears, and writing off bad debt.

To the extent that DERs have the effect of lowering a host customer’s energy bill, it may reduce the probability of the customer falling behind or defaulting on bill payment obligations and therefore result in a utility benefit. This may be a particularly important benefit of DER programs targeted to low-income customers.

These are sometimes referred to as utility-perspective non-energy impacts.

3.5.4.b. Methods for Calculating Credit and Collection Costs Impacts

These costs tend to depend upon the jurisdiction and the utility being assessed. Some utilities are required to routinely file with regulators information pertaining to their costs associated with arrearages, terminations, and other activities related to credit and collection costs (see Narragansett Electric 2021). Many utilities file information on these types of costs as part of their rate cases. In the absence of such publicly available information, these costs can be obtained through information requests to the relevant utility.

Literature reviews can provide some useful information regarding credit and collection costs in other states. (See NEEP 2017 and NMR 2011.)

3.5.4.c. Resources for Calculating Credit and Collection Costs Impacts

International Energy Agency. 2014. (IEA 2014). Capturing the Multiple Benefits of Energy Efficiency. www.iea.org/reports/capturing-the-multiple-benefits-of-energy-efficiency

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4. Gas Utility System Impacts

4.1. Introduction

4.1.1. Applications

This section describes the methods and resources that are used to estimate how changes in natural gas use caused by DER programs will affect the cost of supplying gas to end-use customers. Natural gas system impacts are relevant in several BCA applications:

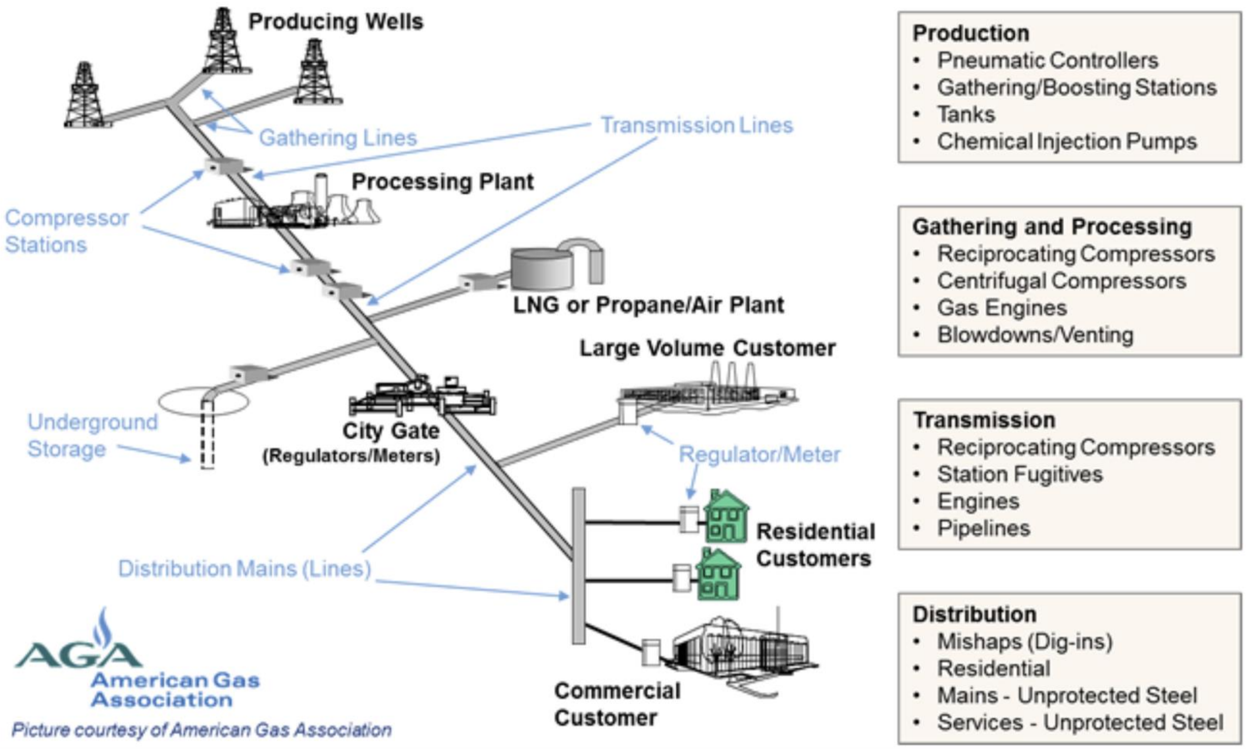
- When gas utilities implement or support DERs that reduce or increase end-use gas consumption, including non-pipe alternatives.
- When electric utilities implement or support DER programs that reduce or increase end-use gas consumption.
- When electric or gas DERs increase or decrease electricity generation and thereby affect marginal gas-fueled power plants on the electricity system. The resulting gas impacts are used as inputs to the energy generation impacts discussed in Section 3.2.1.
- When BCAs are conducted to inform decisions regarding the decarbonization of the gas industry.

The discussion below addresses gas utility system impacts relevant for each of these applications.

4.1.2. Overview of the Gas Utility System

Figure 22 shows different components of the natural gas industry in the United States, from the production wells to the end-use customers. The natural gas industry can be divided into four major segments: (1) production, (2) gathering and processing, (3) transmission and storage, and (4) distribution. Because the industry is not vertically integrated, BCA studies generally focus on the costs that occur after natural gas enters the transmission network and use market prices to capture the costs that occur before that.

Figure 22. Components of the gas industry in the United States



Source: "Overview of the Oil and Natural Gas Industry," No date. EPA.gov website. Attribution: American Gas Association.

The cost of supplying natural gas to end-use customers generally has three parts:

1. The commodity value, which is the market price of natural gas at the location where the gas is purchased.
2. The costs associated with the gas transmission, storage, and peaking facilities that deliver gas into the distribution system.
3. The distribution system costs to deliver gas to the end-use customer meter.

The first two categories correspond to the gas supply costs that local distribution companies (LDCs) generally recover from customers through the cost of gas rate. The gas transmission, storage, and peaking resource costs in the second category are sometimes referred to as capacity costs. The costs in the third category are included in the LDC's base distribution rate.[9]

4.1.3. General Method for Calculating Gas Impacts

The gas utility system impacts of DERs can be estimated by identifying the applicable marginal gas supply resources and multiplying the per-unit cost (usually defined in dollars per MMBtu) by the change

[9] LDC rate structures can also include the costs associated with in-franchise peak shaving and storage facilities that are included in some LDC cost of service.

in gas use. In general, the cost inputs to this analysis include: (a) commodity costs for each of the costing periods being used for the analysis; (b) transmission, storage, and peaking costs for each of the costing periods; and (c) distribution system costs.

The choice of costing periods will depend on the characteristics of the DER program being analyzed. For example, a gas utility demand response program may lower gas use only during periods of peak gas use, while a gas utility energy efficiency program, such as a water heating program, might reduce gas use throughout the year and have a relatively small impact on peak day requirements.

Several different costing period definitions can be used for this purpose. Examples of costing periods include the following:

4. peak day and average day;
5. peak day, next nine days, rest of winter period, and rest of year (see AESC 2021, page 40); and
6. calendar months.

Monthly costing periods are commonly used when measuring gas cost impacts of natural gas use for electricity generation. Note that monthly costing periods can miss the impacts of high demand days with extreme prices when the electric generator does not hold firm delivered pipeline capacity to the plant.

4.2. Gas Commodity Impacts

4.2.1. Definition

Gas commodity impacts include the costs of purchasing gas at specific locations on the gas system and the variable cost of getting the gas where, and when, it will be used. Natural gas may be purchased:

- within the gas production area;
- at an intermediate market center or hub;
- at the interconnection between a gas transmission system and an LDC (called the "city gate"); or
- at a transmission pipeline meter where gas is delivered directly to an electricity generator or large industrial end-user, bypassing the gas distribution system.

Natural gas is traded as a daily quantity (MMBtu or Mcf per Day). Daily gas deliveries can be "baseload" (a firm, fixed volume of gas which the counterparty commits to purchase each day of a given month for the duration of the contract) or "swing" (a variable daily quantity within a maximum and minimum range). Baseload contracts for the next calendar month are traded toward the end of the previous month. Intra-month "spot" trading is generally done on the last business day before the gas flow day ("day-ahead" purchases).

LDCs typically maintain a portfolio of gas supply resources. These portfolios can include gas purchased at upstream supply points and transported to the city gate on pipeline capacity held by the LDC, and "delivered gas" purchased at the city gate from gas marketers that have access to transportation service on the connecting pipeline.

4.2.2. Methods for Calculating Gas Commodity Impacts

Calculating gas commodity impacts typically starts with forecasts of natural gas prices. In most cases it is only necessary to develop commodity price forecasts for the gas supply resources and purchase locations that are expected to be on the margin during one or more costing periods. The marginal gas supply sources and transportation paths can often be identified from LDC regulatory filings, such as integrated resource plans, rate case testimony, and cost of gas rate applications. These filings typically include information about the supply resources that the LDC plans to acquire to meet projected growth in gas use, or the resources that could be reduced or eliminated if gas use declines.

The impact of a DER on natural gas system commodity costs can also be calculated directly using a dispatch simulation model, such as the Ventyx SENDOUT model. Because these models determine the least-cost dispatch of all available supply resources available to the LDC, this method avoids the need to make assumptions about which resources will be on the margin in each costing period. The impact on commodity costs is calculated by running the dispatch model first with the DER excluded (i.e., a Reference Case), and a second time with the gas use forecast adjusted to include the effect of the DER (i.e., a DER Case). The disadvantage of this approach is that it requires detailed resource descriptions and price forecasts for all of the resources in the LDC supply portfolio.

There are two commonly used methods for developing natural gas price forecasts, shown in Figure 23.

Figure 23. Summary of methods for calculating gas commodity impacts

Henry Hub Plus Basis Method	Gas Market Models Method
• Use Henry Hub prices as benchmark for forecasting prices at other locations • Add a "basis" forecast to Henry Hub price to develop price forecast for each location • Convert price forecasts to costing periods	• Obtain price forecasts directly from natural gas market models • Convert price forecasts to costing periods

Option 1: Henry Hub Plus Basis

Henry Hub prices are often used as the benchmark for forecasting prices at other locations. The price forecast for each location is developed by adding a "basis" forecast to the Henry Hub price.

Henry Hub price forecast

Natural gas future prices are common sources for *short-term* price forecasts. Natural gas futures prices are not forecasts, per se, but they are widely used as an indicator of market expectations for natural prices at key hubs throughout the United States. Futures prices for gas delivered at Henry Hub are available from public sources (see CME Group, Henry Hub).

Price forecasts can be based on the futures contract settlement prices for a single trading day or, to reduce the effect of day-to-day volatility, on an average of settlement prices over a longer time period. Futures contracts are listed for a period of 12 calendar years, but trading activity drops off after the first two years. Because the lack of trading activity means that the settlement prices for later periods are less meaningful, a common practice is to use the futures prices for the first two or three years of the study period, and then transition to a long-term price forecast from another source.

The most common source of *long-term* price forecasts for the Henry Hub is U.S. EIA's Annual Energy Outlook, which provides annual values for the Henry Hub Spot Price for a 30-year period (see U.S. EIA AEO 2022). The main advantage of the AEO forecast is that it is publicly available and well documented. The AEO also includes forecasts for multiple scenarios in addition to the Reference Case. Price forecasts for Henry Hub and other major market centers can also be obtained from other gas market models, some of which are discussed below.

Basis forecasts

There are two alternatives for creating basis forecasts.

First, financial derivatives, such as basis futures and swaps, are used to hedge natural gas prices relative to the Henry Hub price for a number of trading locations. The Intercontinental Exchange provides a platform for trading natural gas basis futures (see AESC 2021, page 28). Forward basis prices are also available from information services such as Natural Gas Intelligence (see NGI 2021) and S&P Global (see S&P Global 2021).

Second, a basis relationship can be calculated by taking the difference between the historical prices for Henry Hub and the historical prices for the trading hub or market area that corresponds to the location where gas will be purchased. Historical basis data should be used carefully because changes in gas market flows and pipeline infrastructure can lead to long-term changes in basis values. For this reason, when using historical basis data for forecasting purposes it would be best to first consider whether the historical basis relationship is likely to remain a reasonable indication of the future relationship.

Option 2: Gas Market Models

Price forecasts for many gas trading locations can be obtained directly from natural gas market models. For example:

- The GPCM® is a widely used tool for "developing market simulations for scenario analysis and forecasts for North American gas flows, price and basis. It is a complete system of interrelated models for simulating gas production, pipeline and storage capacity utilization, deliveries to LDCs, utilities, and industrial consumers, as well as commodity price at points throughout the North American market" (see RBAC GPMC 2021).
- The California PUC uses price forecasts for the two major LDC city gates from the California Energy Commission's North American Market Gas-trade model (NAMGas) (see CPUC 2020, page 9). The NAMGas model also produces publicly available price forecasts for other gas trading hubs.
- ICF provides a commercially available market forecast for most major market centers using the ICF Gas Markets Model (GMM) (see ICF GMM). The GMM forecasts monthly North American gas production, flows, prices, and basis through 2050.

Converting gas price forecasts to costing periods

Regardless of which option is used, it is also necessary to convert the gas price forecasts to costing periods. Long-term natural gas price forecasts are often calendar-year forecasts that do not correspond to the costing periods being used for the BCA. A common practice is to develop patterns from historical prices or near-term futures prices and apply these multipliers to the annual or monthly forecasts to calculate costing period values. Historical natural gas prices are available for monthly baseload contracts and day-ahead sales for many active trading locations. Price reporting services such as Platts (owned by

S&P Global) compile indexes from transaction information obtained from confidential surveys (see Platts 2022).

Variable transportation, storage, and peaking costs

Gas commodity costs also need to include variable transportation, storage, and peaking costs that are incurred after gas is purchased. Methods for estimating these costs are described in Section 4.4.

4.2.3. Method for Calculating the Cost of Gas Used by Electricity Generators

Electricity generators often receive natural gas directly from a gas pipeline operator or from LDCs for unbundled gas transportation service. This is often done through special contracts or tariffs where the distribution cost varies less with changes in gas use than a standard distribution tariff rate. In this situation, the applicable gas supply cost is the commodity price for the gas market area where the generator is located, with typically no capacity or distribution costs added.

4.2.4. Resources for Calculating Gas Commodity Impacts

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4.3. Gas Wholesale Market Price Effects

4.3.1. Definition

Wholesale market prices are a function of the demand of buyers and the marginal costs of suppliers. When DERs reduce (or increase) the demand for gas, they reduce (or increase) the wholesale market prices, which creates benefits (or costs) for all customers participating in the wholesale market at that time. Even a very small perturbation of the market price can have large impacts when applied across all wholesale customers. This effect is sometimes referred to as demand reduction induced price effect (DRIPE).

4.3.2. Method for Calculating Gas Wholesale Market Price Effects

The wholesale gas market price effects can be calculated using the steps in Table 50.

Table 50. Steps to calculate gas wholesale market price effects

Step 1	**Estimate the wholesale gas price elasticity** This is the "price shift," which represents the change in gas price ($/MMBtu) for a change in gas demand (MMBtu). Aggregated over many data points, this price shift represents the supply curve of a particular DER. Wholesale gas price elasticities are best estimated using an integrated natural gas market forecasting model to assess the impact of a specific change in demand on gas prices at specific market locations. In the absence of such a model, wholesale gas price elasticities can be calculated using a regression analysis, where many historical datapoints are analyzed to establish a relationship between prices and demand. Information for these regression analyses can be obtained from the U.S. EIA (see U.S. EIA AEO 2022).[10]
Step 2	**Express the price shift in terms of price-per-demand (in $/MMBtu of demand)** This can then be applied to any generic change in demand. This can be achieved by multiplying the price elasticities by total future market demand. The price-per-demand value can then be multiplied by a DER's anticipated savings to determine the wholesale market price effect.
Step 3	**Adjust the price-per-demand value to account for market conditions that affect the magnitude of the wholesale market price effect** For gas markets, a portion of non-electric gas consumption is often locked up in short-term contracts and is therefore unresponsive to price changes. Therefore, this portion of gas consumption should be excluded from the calculation. For example, the AESC study assumes that the percentage of non-electric natural gas consumption which is unresponsive to DRIPE varies by year: in year one, 50 percent is assumed unresponsive; in year two, 20 percent is assumed unresponsive; and in year three and all years thereafter 0 percent is assumed unresponsive (see AESC 2021, pages 217 – 218).

[10] Note that there is no one price elasticity for all points on the gas system. The price impact decreases as you move further away from the demand impact. Hence it may be appropriate to use one price impact for the LDC service territory demand but expanding to the state level would require a smaller price impact and expanding to a regional or national impact would require an even smaller impact.

4.3.3. Resources for Calculating Gas Wholesale Market Price Effects

Avoided Energy Supply Components Study Group. 2021. (AESC 2021). *Avoided Energy Supply Components in New England: 2021 Report*. Prepared by Synapse Energy Economics, Resource Insight, Les Demans Consulting, Northside Energy, Sustainable Energy Advantage.

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4.4. Gas Transmission, Storage, and Peaking Impacts

4.4.1. Definition

LDCs typically purchase transmission, storage, and peaking services, or use on-system storage or peaking facilities, to ensure that gas is reliably available when it is needed. Natural gas is stored in depleted gas and oil fields and other underground structures, such as aquifers and salt caverns. Gas is also stored in aboveground tanks as LNG or CNG. Peaking gas supply contracts allow the LDC to call on gas delivered at the city gate during periods of peak gas demand, up to a defined daily quantity and total contract amount. On–system peaking facilities inject vaporized LNG, propane, or compressed natural gas (CNG) directly into the distribution system to supplement the gas supply.

4.4.2. Methods for Calculating Pipeline Transportation Impacts

For most LDCs, the main source of gas capacity costs is the fixed charges for pipeline transportation services that deliver natural gas to the LDC city gate. LDCs typically enter into long-term contracts for pipeline delivery capacity with the option to terminate or continue service at the end of the initial contract term.

Three options for estimating gas transportation costs are described below in Figure 24. Note that if the only gas supply resource is delivered gas purchased at city gate, this step can be omitted. This is often the case for electricity generators that buy gas at pipeline delivery meters that connect directly to the generating plant. Transportation costs are typically included in the wholesale prices that these generators pay for gas fuel and therefore do not need to be determined separately.

Figure 24. Methods for calculating pipeline transportation impacts

Pipeline Tariff Rates Method	Incremental Project Rates Method	Basis Method
• Determine if standard rates are likely to apply (no expansion expected) • Access current standard rates for interstate pipelines from Informational Postings page on pipeline operator's website	• Determine if incremental rates are likely to apply (expansion expected) • Access estimated transportation rates for interstate pipeline expansion projects under development in certificate applications filed with FERC • Access actual transportation rates for interstate pipeline expansion projects in FERC filings from in-service date	• Use difference between Henry Hub price and retail prices paid by end-use customers as a measure of total transmission and distribution costs for avoided cost analysis

Option 1: Pipeline Tariff Rates

The rates charged by natural gas transmission pipelines in United States are approved by the Federal Energy Regulatory Commission (FERC) and state utility commissions. For interstate pipelines, the tariff rates that are currently in effect can be accessed from the Informational Postings page on the pipeline operator's website. Transportation charges include the fixed monthly reservation charge, which is paid on the maximum daily quantity that the pipeline operator is obligated to receive and deliver for the customer (or "shipper") on a given day, and a variable charge based on the pipeline's variable O&M costs. Pipeline operators also retain a percentage of the gas transported to recover gas used for compressor fuel.

Option 2: Incremental Project Rates

FERC requires natural gas pipeline operators to charge higher "incremental" rates for expansion projects whenever including costs in the standard transportation rate calculation would lead to a subsidization of the project by existing shippers. This means that the transportation rate under a new transportation service agreement can be substantially higher than the rate paid for the same transportation service by shippers holding older contracts.

Choosing which gas transportation rate to use for a BCA will depend on whether gas use is increasing or decreasing, and whether pipeline capacity is expected to be available without new pipeline infrastructure. If gas transmission capacity is expected to expand, so that the DER program will make the expansion larger or smaller (or avoid the need to expand entirely), it is appropriate to use an incremental rate instead of the standard tariff rate. The impact on the avoided capacity cost can be significant for markets with natural gas pipeline capacity constraints. Southern Connecticut Gas Company, for example, estimates that the cost to obtain additional pipeline transportation service to its city gate is more than five times the standard pipeline tariff rate (see Southern Connecticut Gas Company 2020).

Estimated transportation rates for interstate pipeline expansion projects that are in development can be found in the certificate applications filed with FERC. The actual rates for new transportation service agreements are filed around the time that service begins.

Option 3: Basis

The difference between the Henry Hub price and the retail prices paid by end-use customers can be used as a measure of total transmission and distribution costs for avoided cost analysis (see Exeter 2014, page 45). Historical basis data should be used carefully because changes in gas market flows and pipeline infrastructure can lead to long-term changes in basis values.

4.4.3. Method for Calculating Gas Storage Impacts

LDCs purchase natural gas storage services from pipeline operators and independent storage operators. LDCs may also operate on-system storage facilities that connect directly to the distribution system. Gas storage services generally include fixed charges based on the maximum storage capacity quantity and the maximum daily withdrawal quantity, variable charges based on the actual quantities injected and withdrawn, and in-kind charges for storage compressor fuel.

Since most gas storage facilities are regulated by FERC or state utility commissions, these charges can generally be found in the storage operator's publicly available tariff. Storage facilities operated by LDC involve similar costs, but since these on-system facilities may be physically integrated into the operation of the gas distribution system, these are less likely to be avoidable costs that are affected by a DER program.

There are also significant carrying costs associated with maintaining natural gas storage working gas inventories since the gas in storage must be purchased prior to storage injection, and then held until the gas can be sold after withdrawal.

4.4.4. Methods for Calculating Gas Peaking Impacts

Because LDCs often have more flexibility to adjust their use of gas peaking resources in response to changes in projected end-use customer requirements. Peaking costs are more likely to be avoidable by DERs than, for example, storage costs. Contracts for winter peaking gas delivered at the city gate are often negotiated annually. For on-system peaking facilities, supplies of LNG, propane, and CNG are typically obtained under short-term agreements.

Contracts for peaking resources usually include a fixed reservation charge and a variable charge for the quantity of gas or other fuel that is actually used. However, because the terms of these contracts are often confidential, the actual costs paid by LDCs may not be available from public sources.

4.4.5. Resources for Calculating Gas Capacity Impacts

Avoided Energy Supply Components Study Group. 2021. (AESC 2021). *Avoided Energy Supply Components in New England: 2021 Report*. Prepared by Synapse Energy Economics, Resource Insight, Les Demans Consulting, Northside Energy, Sustainable Energy Advantage.

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Southern Connecticut Gas Company. 2020. *Forecast of Natural Gas Demand and Supply, 2021-2025*. Filed October 1, 2020 in CT PURA Docket No. 20-10-2, page IV-25.

4.5. Gas Distribution Impacts

4.5.1. Definition

The gas distribution system impacts include the LDC costs to deliver gas from the city gate to retail customers. LDCs operate the gas mains that connect the transmission pipelines and on-system storage and peaking facilities to homes, businesses, and industrial facilities within their service territories. LDCs often provide both bundled service, where the customer buys gas from the LDC, and unbundled service, where the customer buys gas from a marketer and the LDC transports the gas to the customer meter.

LDCs typically recover both fixed and variable costs using volumetric rates. LDCs also retain a percentage of the gas delivered to unbundled customers for gas use and loss.

4.5.2. Methods for Calculating Gas Distribution Impacts

There are several options for calculating the gas distribution system impacts, shown in Figure 25.

Figure 25. Methods for calculating gas distribution impacts

LDC Tariffs Method	Historical Margins Method	Marginal Cost of Service Study Method	Engineering Estimates of Avoidable System Upgrade Costs Method
• Access rates on LDC tariff sheets available from LDC website and/or relevant public utility commission website	• Calculate distribution system costs by taking difference between retail price paid by end-use customers and city gate price	• Use existing marginal cost of service studies to obtain calculations of relationship between plant and O&M expenditures and changes in peak day demand	• Use existing engineering studies' estimates of costs avoided by deferring or avoiding the capital projects that would otherwise be required to meet projected growth in natural gas requirements

Option 1: LDC Tariffs

LDC rates are a direct measure of the gas distribution system costs paid by end-use customers. These rates can be found on LDC tariff sheets that are often available from the LDC website and/or the relevant public utility commission website.

The gas distribution costs included in LDC rates typically include sunk costs that would not be avoidable by DERs. Therefore, when estimating gas distribution impacts of DERs, LDC rates should be adjusted downward to reflect the portion of rates that can be avoided by DERs.

Option 2: Historical Margins

Distribution system costs can be calculated by taking the difference between the retail price paid by end-use customers and the city gate price. U.S. EIA publishes state-level data, by month, for the city gate price and end-use customer prices by customer class (residential, commercial, and industrial) (see U.S. EIA STEO).

The gas distribution costs included in historical margins can include sunk costs that would not be avoidable by DERs. Therefore, when estimating gas distribution impacts of DERs, historical margins should be adjusted downward to reflect the portion of rates that can be avoided by DERs.

Option 3: Marginal Cost of Service Study

Marginal cost studies use econometric analysis and engineering estimates to calculate the relationship between plant and O&M expenditures and changes in peak day and annual demand. These studies are used to design rates and to set price floors for negotiated-rate contracts. Marginal cost of service studies are commonly included with LDC rate case applications.

Option 4: Engineering Estimates of Avoidable System Upgrade Costs

Engineering studies estimate the costs that are avoided by deferring or avoiding the capital projects that would otherwise be required to meet projected growth in natural gas requirements. The CPUC uses this approach for most end-use customers but uses LDC tariff rates to calculate costs for electric generators (see CPUC 2020, pages 9-10).

4.5.3. Resources for Calculating Gas Distribution Impacts

Avoided Energy Supply Components Study Group. 2021. (AESC Supplemental 2021 Natural Gas). *AESC Supplemental Study: Expansion of Natural Gas Benefits*. Prepared for AESC Supplemental Study Group. Synapse Energy Economics and Northside Energy.

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4.6. Targeted Non-Pipe Alternatives

4.6.1. Definition

The methods for calculating transportation capacity impacts related to changes in requirements for gas transmission or distribution facilities apply to the usual situations where DERs have a *passive* impact on transportation capacity by reducing or increasing natural gas use.

DERs may *actively* defer pipeline or distribution capacity needs as part of a geographically targeted non-pipe alternative (NPA). This section provides a method for calculating the full set of impacts associated with NPAs. The method is consistent with the method used for NWAs (see Section 3.3.1.c).

4.6.2. Method for Calculating Targeted Non-Pipe Alternatives Impacts

Some DERs can actively defer or avoid investments on specific new pipeline facilities, e.g., through non-pipe alternatives or geographically targeted DERs. In these cases, the pipeline capacity benefits can be determined by calculating the difference in cost between the planned and the deferred installation date of the targeted pipeline investment, using the steps in Table 51 below.

Table 51. Steps to calculate targeted non-pipe alternatives impacts

Step 1	Identify the new transportation facilities that could potentially be avoided by gas DERs Determine the original date of installation of the new transportation facilities.
Step 2	Determine the expected cost of the new transportation facilities (in $) Assume they are installed at the original date of installation (from Step 1).
Step 3	Determine the amount of gas DER savings (in MMBtu) that will be used to defer the transportation facilities (either transmission or distribution) This can be done using the proposed DERs' load impact profiles (see Chapter 11).
Step 4	Determine the number of years that the new transportation facilities might be deferred by the DER In some cases, this might be only a year or two; in others it might be indefinitely.
Step 5	Calculate the expected cost of the new transportation facilities (in $) Assume they are installed at the later date (from Step 4).
Step 6	Calculate the difference in costs (in $) This is the difference between those of the original date (from Step 2) and those of the later date (from Step 4).
Step 7	Calculate the total avoided transportation cost (in $/MMBtu) Divide the difference in costs (from Step 5) by the capacity avoided by the DER (from Step 3).
Step 8	Estimate the annual capital costs (in $/MMBtu-year) Multiply the total avoided transportation costs (in $/MMBtu) from Step 7 by a real economic carrying charge. The carrying charge should reflect the utility's cost of capital, income taxes, property taxes, insurance costs, and operation and maintenance expenses. This data is often available as part of utility marginal cost of service studies.

See AESC Supplemental 2021 Natural Gas, pages 24-34.

4.6.3. Resources for Calculating Non-Pipe Alternative Impacts

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4.7. Gas System Use and Loss

4.7.1. Definition

Much of the natural gas that flows through gas transmission pipelines and gas distribution systems does not reach the end-use customer. Pipeline operators retain a portion of the gas shipped for compressor fuel, to account for measurement errors, and for actual gas losses.

At the gas distribution level, the difference between the total quantity of gas measured entering the LDC system and the total quantity of gas used delivered to end-use customers or used for gas utility operations is often referred to as lost and unaccounted for (LAUF) gas.

4.7.2. Methods for Calculating Gas System Losses

There are two methods commonly used to estimate losses in the gas system, described in Figure 26.

Figure 26. Methods for calculating gas system losses

Tariff Rates Method

- Determine if relevant state tracks LAUF using NRRI survey
- Obtain fuel retainage and LAUF factors from tariff rate postings available on pipeline operator or LDC website
- Determine which categories to include in BCA

Methane Emission Studies Method

- Determine system loss rates using existing studies that analyze gas industry methane emissions to address climate change concerns

Option 1: Tariff Rates

Natural gas pipeline operators and LDCs typically include fuel retainage and LAUF factors with their tariff rate postings. These factors are generally approved by FERC or state regulators and made available on the pipeline operator or LDC website.

However, delivery loss rates can sometimes be challenging to estimate due to lack of data, differences in costing periods, and more. A 2013 NRRI survey of state regulatory commissions indicates that some states track and report LAUF while many do not. It provides a list of states that report LAUF as well as the LAUF percentages where they are available (see NRRI 2013, pages 91-94).

It is also necessary to determine which categories of use and loss to include in the BCA. For example, by adjusting for gas that the LDC uses for system operations, such as compressors and gas heaters, but excluding losses tied to leakage and inaccurate measurement because these losses are not considered to be directly avoidable.

Option 2: Methane Emission Studies

Gas system loss rates can be determined from studies that analyze gas industry methane emissions to address climate change concerns.[11] These studies often look at leakages from the entire gas system, including from wellheads, processing transmission and delivery, and end-use (see Section 7.1.2).

Note that both options described above will typically provide average system losses, rather than marginal losses. Average system losses might be reasonable approximations of marginal losses for many DER types. For some projects, however, additional analysis might be needed to develop marginal losses.

4.7.3. Resources for Gas System Losses

Avoided Energy Supply Components Study Group. 2021. (AESC 2021). Avoided Energy Supply Components in New England: 2021 Report. Prepared by Synapse Energy Economics, Resource Insight, Les Demans Consulting, Northside Energy, Sustainable Energy Advantage.

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California Public Utilities Commission. 2020. (CPUC 2020). Distributed Energy Resources Avoided Cost Calculator Documentation for the California Public Utilities Commission. Version 1c. Prepared by Energy and Environmental Economics, Inc. June.

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U.S. Environmental Protection Agency. 2018. (U.S. EPA 2018). Quantifying the Multiple Benefits of Energy Efficiency and Renewable Energy: A Guide for State and Local Governments. www.epa.gov/statelocalenergy/quantifying-multiple-benefits-energy-efficiency-and-renewable-energy-guide-state.

[11] There is a distinction between accounting losses and actual methane leakage. Accounting losses are the difference between MMBtu measured at the meter and MMBtu measured at the customer, and thus include differences in meter calibration as well as methane leakages. Almost all of the reported data is based on accounting losses.

U.S. Environmental Protection Agency. n.d. (U.S. EPA GWP). "Understanding Global Warming Potentials." epa.gov website. www.epa.gov/ghgemissions/understanding-global-warming-potentials.

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Zhang et. al. 2020. "Quantifying methane emissions from the largest oil producing basin in the U.S. from space: Methane emissions from the Permian Basin." Science Advances p. 1-39. legacy-assets.eenews.net/open_files/assets/2020/04/23/document_ew_03.pdf.

4.8. Gas Environmental Compliance Impacts

4.8.1. Definition

4.8.1.a. Overview

Gas utilities are required to incur costs for compliance with environmental requirements. These costs are then passed on to all gas customers through revenue requirements and rates. Many such requirements are included in gas fuel and capacity impacts and therefore do not need to be calculated separately.

GHG mandates are a primary environmental requirement that might need to be estimated separately from other fuel impacts. GHG mandates are an increasingly common type of environmental compliance cost in some states. These mandates sometimes require emission reductions relative to a benchmark amount (e.g., 1990 emissions) or sometimes place a cap on total emissions. They sometimes limit emissions by a single target year (e.g., 2030), or sometimes limit emissions by increasing amounts for several target years (2030, 2040, 2050).

The U.S. EPA recently proposed requirements for reducing methane emissions from natural gas transmission and storage facilities (See U.S. EPA website, Methane Standards). These new requirements are likely to impose costs on natural gas that are not accounted for in historical costs or in current forecasts.

4.8.1.b. Relationship to Societal Environmental Impacts

Societal environmental impacts are the impacts on the environment that occur in the absence of environmental requirements or after the environmental requirements have been met. It is important to distinguish between environmental compliance impacts and societal environmental impacts (see Section 3.2.6.).

- Environmental compliance impacts are the direct impacts in dollar terms that will be incurred by the utility and passed on to all customers through revenue requirements and customer rates.
- Societal environmental impacts are imposed on society as a whole but do not affect the cost of gas services.

4.8.1.c. Anticipated Environmental Requirements

A BCA should account for all environmental requirements expected to be in effect over the study period (see RAP 2012; RAP 2013, pages 32-37). This should include requirements that are already established by statutes, regulations, orders, or other directives, even if they have not taken effect yet. If a particular requirement is expected to take effect in three years, for example, then the implications of that anticipated requirement should be applied in the third year of the BCA study period and beyond.

Similarly, BCAs should also account for environmental requirements that have not yet been established but are reasonably likely to be established within the study period. Environmental regulations often become more stringent over time (see RAP 2013, page 29) and failure to account for such changes will understate the actual environmental compliance costs.

> BCAs should account for all environmental requirements expected to be in effect over the study period, including those in place but not yet in effect, and those that are not in place but are likely to be in place during the study period.

There may be situations where it is not entirely clear whether environmental requirements will be imposed on the gas utility. For example, a state might establish a GHG target, but the target is not a binding mandate, or the target is applied to the entire economy and not explicitly applied to gas utilities. In these situations, stakeholders and regulators should estimate the most likely timing and magnitude of the targets on the utilities using the best information available. To completely ignore the GHG targets will understate the costs of compliance with them in the BCA. This could result in implementation of fewer DERs, which could ultimately result in higher costs to comply with the targets once they are applied to the utilities.

There will inevitably be some uncertainty about anticipated environmental regulations, just as there is uncertainty about most of the impacts discussed in this MTR handbook. A variety of techniques can be used to address this uncertainty, as described in Chapter 10.

4.8.2. Methods for Calculating Impacts of Compliance with GHG Mandates

Figure 27 summarizes two common methods for estimating impacts of compliance with gas utility GHG mandates.

Figure 27. Methods for estimating impacts of compliance with gas utility GHG mandates

GHG Cost Method

- MAC method: create marginal abatement cost curve to determine the cost of GHG in terms of $/ton
- SCC method: use social cost of carbon estimates from US IWG to determine the cost of GHG in terms of $/ton

Planning Constraints Method

- Design Reference and DER Cases to comply with GHG mandates using the lowest cost resources available in each case

4.8.2.a. GHG Cost Method

Option 1: Marginal Abatement Cost Method

A relatively simple method for estimating the cost of compliance with GHG mandates is to identify the GHG abatement resource that is most likely to be the marginal resource to meet the mandate. The marginal abatement option can be identified by developing a marginal abatement cost curve.

The MAC method for estimating impacts of compliance with electric utility GHG mandates is described in Section 3.2.6.b. The same approach can be used for estimating impacts of compliance with gas utility GHG mandates.

Option 2: Social Cost of Carbon Method

The SCC method represents another way to estimate the cost of carbon in terms of $/ton. It uses the "damage-based" approach to estimate this cost, instead of the "abatement-based" approach of the MAC. The SCC is based on the dollar value of the net cost to society from adding a ton of GHG to the atmosphere in a particular year. Costs include the net impacts to agricultural productivity, human health effects, property damage from flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of impacts to ecosystems (see U.S. IWG 2021).

The SCC method can be used to estimate the cost of complying with a GHG mandate only in those jurisdictions that have a mandate to achieve a *societal* abatement goal, e.g., net zero GHG emissions by 2050. Jurisdictions that have a GHG mandate that is less stringent than this societal abatement goal should not use the SCC method. Instead, they should use the MAC method, where the marginal abatement option is based upon the specific GHG abatement goal of the jurisdiction.

The SCC method for estimating impacts of compliance with electric utility GHG mandates is described in Section 3.2.6.b. The same approach can be used for estimating impacts of compliance with gas utility GHG mandates.

Comparison of the Social Cost of Carbon and the Marginal Abatement Cost Methods

Section 7.1.2 provides a comparison of the MAC and SCC methods for estimating either environmental compliance costs or societal GHG impacts. This comparison is summarized in Table 52.

Table 52. Comparison of societal cost of carbon and marginal abatement cost methods

Method	Description	Applications	Advantages	Disadvantages
Social Cost of Carbon	Based on future global damage costs from climate change	1. For determining the total social cost of GHG emissions 2. For determining the cost of compliance with GHG mandates that require meeting a societal GHG goal, e.g., net zero emissions by 2050	• Values are readily available • Values are credible because they were developed and vetted by global experts and federal agencies • Can be applied to emissions from any sector • Does not require a specific carbon reduction target	• Involves considerable uncertainty and debate about future damage costs • Value is extremely sensitive to the discount rate chosen and complex modeling assumptions • Can only be used to determine total social cost of GHG emissions
Marginal Abatement Cost	Based on cost of technologies and other options that can be used to abate GHG emissions to a desired level in the jurisdiction of interest	1. For determining the total social cost of GHG emissions, if a societal GHG goal is used, e.g., net zero emissions by 2050 2. For determining the cost of complying with specific GHG targets	• Well-suited for determining the cost of compliance with GHG targets that are less stringent than a societal GHG goal • Based on known technologies with known costs relevant to the jurisdiction • Reveals the actual costs that might need to be incurred to meet GHG target	• Requires concrete emission abatement targets • Values not easily available; estimates are complex and resource-intensive • Ideally requires analysis for multiple sectors (electric grid, building, transportation, industry)

4.8.2.b. Planning Constraints Method

The most accurate approach for estimating the cost of complying with GHG mandates is to use those mandates as a constraint in the resource plans created to estimate avoided costs. In other words, the Reference Case and the DER Case (and any sensitivities) should be designed to comply with the GHG mandate using the lowest cost resources available in each case. The Reference Case will have to rely upon a set of clean energy options that does not include new DERs, while the DER Case may not need as many other clean energy options because of the GHG emission reductions available from the DERs.

The difference in costs between the Reference Case and the DER Case will represent the avoided costs of the system, including the avoided costs of achieving the GHG mandates. In other words, the avoided costs of achieving the GHG mandates will not be identified separately from the other avoided costs. If a separate estimate of the avoided costs of the GHG mandate is desired, then one could do a sensitivity analysis comparing a hypothetical Reference Case that does not meet the GHG mandate with the Reference Case that does meet the GHG mandate. The difference in costs between these two cases will indicate the avoided cost of compliance with the mandate, in the absence of the new DERs.

The advantage of this method is that it is the most accurate way to identify the incremental cost of complying with the GHG mandate, because it is based upon a least-cost modeling of all the GHG abatement options. The disadvantage of this method is that it can be labor intensive.

4.8.3. Resources for Calculating Impacts of Compliance with GHG Mandates

Regulatory Assistance Project. 2012. (RAP 2012). Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for 'Other Program Impacts' and Environmental Compliance Costs. T. Woolf et al., Synapse Energy Economics. www.synapse-energy.com/sites/default/files/SynapseReport.2012-11.RAP_.EE-Cost-Effectiveness-Screening.12-014.pdf.

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Smart Electric Power Association. 2021. (SEPA 2021). "Utility Carbon-Reduction Tracker™" sepapower.org website. sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/.

U.S. Environmental Protection Agency. n.d. (U.S. EPA Methane). "Methane Standards." epa.gov website. www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-proposes-new-source-performance.

United States Government. 2021. (U.S. 2021 NDC). The United States of America Nationally Determined Contribution—Reducing Greenhouse Gases in the United States: A 2030 Emissions Target. www4.unfccc.int/sites/ndcstaging/PublishedDocuments/United%20States%20of%20America%20First/United%20States%20NDC%20April%2021%202021%20Final.pdf.

4.9. Gas Utility General Impacts

4.9.1. Financial Incentives Provided by Utility

4.9.1.a. Definition

This impact includes utility financial support provided to DER host customers or other market actors (e.g., retailers, contractors, distributors, manufacturers, integrators, and aggregators) to encourage DER implementation.

Financial incentives may come in various forms, including the following:

- incentives or rebates,
- buy-downs of interest rates for financing a portion of DER costs,
- payments to support trade ally reporting on sales of DERs,
- funding or co-funding of marketing of DER equipment by trade allies, and
- sales bonuses provided to retail or contractor sales staff for selling DER equipment.

4.9.1.b. Methods For Calculating Financial Incentive Impacts

The financial incentives offered to program participants and host customers are typically designed to overcome the market barriers that prevent customers from adopting DERs on their own. They can be based on a variety of factors, including customer surveys (how much is needed to change behavior); payback periods; results from evaluation, measurement, and verification studies; market studies (percent penetration); or rate classifications (e.g., 100-percent incentives for low-income). The financial incentives offered for a DER will depend upon the jurisdiction, the utility, the program design, the DER type, the customer type, and more. Consequently, this information is best obtained by requesting it from the utility, the DER program administrator, or other stakeholders involved in the development of the DER program.

If information is not readily available from the utility or program administrator, these impacts can sometimes be estimated by using data from comparable programs offered by other utilities or program administrators.

4.9.1.c. Resources For Calculating Financial Incentives Impacts

Some energy efficiency and demand response program administrators present information on financial incentives in the prospective energy efficiency plans that they file with regulators to obtain approval of the plans.

4.9.2. Program Administration Costs

4.9.2.a. Definition

Program administration costs are those incurred by the utility related to the planning, design, implementation, and evaluation of a DER program or initiative.

These costs may come in a variety of forms, including costs to support utility outreach to trade allies, technical training, other forms of technical support, marketing, administration, and management of DER programs or portfolios of programs. Administration costs also often include evaluation, measurement, and verification studies to inform either DER program design or retrospective assessment of DER performance.

4.9.2.b. Methods for Calculating Program Administration Costs

DER program administration costs will depend upon the jurisdiction, the program administrator, the program design, the DER type, the customer type, and more. Consequently, this information is best obtained by requesting it from the utility, the DER program administrator, or other stakeholders involved in the development of the DER program.

In some cases, it might be possible to use rough estimates of program administration costs from similar jurisdictions with similar programs. For example, by applying administration costs as a percentage of the total DER program budget to the DER program of interest. This approach, however, should be used with caution because the administration costs can vary depending upon the administrator—even for similar DER programs.

4.9.2.c. Resources For Calculating Program Administration Costs

Most energy efficiency and demand response program administrators present information on program administration costs in the prospective energy efficiency plans that they file with regulators to obtain approval of the plans.

4.9.3. Utility Performance Incentives

4.9.3.a. Definition

In many jurisdictions, utilities are offered shareholder incentives for meeting specific performance metrics related to the success of DER programs. These performance incentives represent a cost associated with the delivery of the DER program.

DER performance incentives can take many forms, including shared savings mechanisms, payments for meeting energy savings targets, payments for meeting capacity savings targets, or combinations of the above. Performance incentives can take the form of rewards, or penalties, or both.

Energy efficiency and demand response programs are frequently supported by utility performance incentives, while it is much less common for such incentives to be applied to other types of DER programs.

4.9.3.b. Methods for Calculating Utility Performance Incentives

Performance incentives are typically set by legislation or regulators and are usually unique to a jurisdiction, state, or utility. They can sometimes be obtained from relevant legislation, regulations, or commission orders. They might also be available from commission dockets used to establish performance incentive mechanisms for a variety of utility services.

Otherwise, this information can be obtained by requesting it from the utility, the DER program administrator, or other stakeholders involved in the development of the utility performance incentive.

4.9.3.c. Resources for Calculating Utility Performance Incentives

Some energy efficiency and demand response program administrators present information on utility performance incentives in the prospective energy efficiency plans that they file with regulators to obtain approval of the plans.

American Council for an Energy Efficient Economy. 2015. (ACEEE 2015 Performance Incentives). *Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency.* Nowak, Baatz, Gilleo, Kushler, Molia, and York. May.

4.9.4. Credit and Collection Costs

4.9.4.a. Definition

This includes costs associated with customers who are deficient on energy bill payments, including notices and support provided to customers in arrears, terminations, disconnections, reconnections, carrying costs associated with arrears, and writing off bad debt.

To the extent that DERs have the effect of lowering a host customer's energy bill, they might reduce the probability of the customer falling behind or defaulting on bill payment obligations and therefore result in a utility benefit. This may be a particularly important benefit of DER programs targeted to low-income customers.

These are sometimes referred to as utility-perspective non-energy impacts.

4.9.4.b. Methods for Calculating Credit and Collection Costs

These costs tend to depend upon the jurisdiction and the utility being assessed. Some utilities are required to routinely file with regulators information pertaining to their costs associated arrearages, terminations, and other activities related to credit and collection costs (see Narragansett Electric 2021). Many utilities file information on these types of costs as part of their rate cases. In the absence of such publicly available information, these costs can be obtained through information requests to the relevant utility.

Literature reviews can provide some useful information regarding credit and collection costs in other states. (See NEEP 2017 and NMR 2011.)

4.9.4.c. Resources for Calculating Credit and Collection Costs

International Energy Agency. 2014. (IEA 2014). *Capturing the Multiple Benefits of Energy Efficiency*. www.iea.org/reports/capturing-the-multiple-benefits-of-energy-efficiency.

Narragansett Electric. 2021. Low-Income Monthly Reports. Filed with the Rhode Island Public Utility Commission.

Tetra Tech, NMR Group. 2011. *Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation*. Prepared for the Massachusetts Program Administrators. ma-eeac.org/wp-content/uploads/Residential-and-Low-Income-Non-Energy-Impacts-Evaluation-1.pdf.

Northeast Energy Efficiency Partnerships. 2017. (NEEP 2017). *Non-Energy Impacts Approaches and Values: An Examination of the Northeast, Mid-Atlantic, and Beyond*. June. neep.org/sites/default/files/resources/NEI%20Final%20Report%20for%20NH%206.2.17.pdf.

5. Other Fuel System Impacts

5.1. Introduction

Electric and gas utility DERs can affect other types of fuels, such as oil, propane, diesel, biomass (including wood), or gasoline. Unlike electricity and gas, these fuels are not price-regulated. Much of the information needed to determine the impacts of these fuels can be obtained from publicly available price forecasts.

Notable examples or DERs that affect other fuels include:

- An electricity or gas energy efficiency program that targets space heating and reduces consumption of oil, propane, or wood.
- An electricity demand response program that reduces the use of diesel back-up generators.
- A distributed combined heat and power program that relies upon biomass to fuel the generator.
- A building electrification program that encourages customers to switch space heating systems from those the use oil, propane, or wood.

An electric vehicle program that results in reduced gasoline consumption.

5.2. Fuel Supply Impacts

5.2.1.a. Definition

Other fuel supply impacts include the costs incurred by other fuel suppliers for procurement, O&M, and delivery of fuel on behalf of retail customers. In most cases, all of these costs are included and bundled in the price of the fuel.

Unlike electricity and gas prices, other fuel oil prices do not show meaningful predictable variations by hour, day, month, or even or season because they can be stored much more inexpensively. Consequently, these impacts can be determined and used on an annual basis.

5.2.1.b. Method For Calculating Other Fuel Supply Impacts

For most other fuels, the fuel supply impacts are fully represented in the retail price of the fuel. Therefore, the primary method for determining these impacts is to simply refer to publicly available retail price forecasts for these fuels.

Price Forecasts for Oil

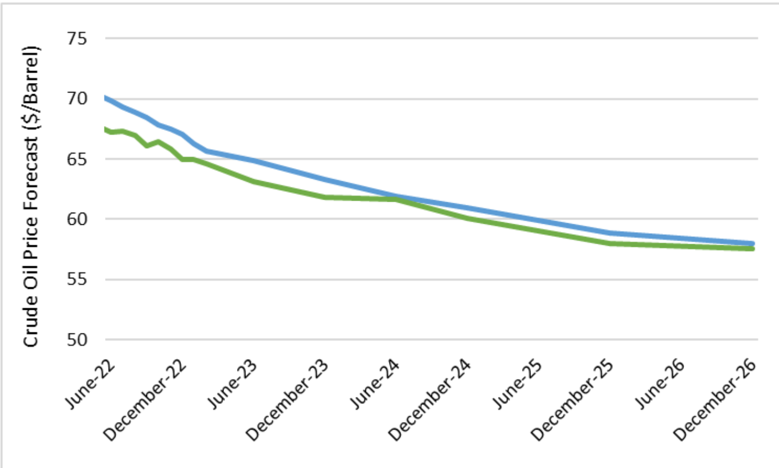
U.S. EIA provides a variety of oil and petroleum product price forecasts.

Short-term forecasts are available from U.S. EIA's Short-Term Energy Forecast. These price forecasts are released periodically throughout the year and are based on short-term oil market fundamentals, whereas the long-term forecasts are prepared only once per year and focus on longer-term market fundamentals (see U.S. EIA STEO).

Long-term price forecasts are available from U.S. EIA's Annual Energy Outlook. These price forecasts are released annually and are based on an assessment of long-term oil market fundamentals (see U.S, EIA AEO 2021).

Short- to mid-term oil price forecasts are available from other sources (see CME Group, Oil). These forecasts might vary a little from AEO forecasts because they represent the expectations of the market (i.e., buyers and sellers of oil products) rather than an assessment of oil market fundamentals. Figure 28 presents futures for crude oil through December 2026.

Figure 28. Crude oil futures



Data source: CME Group, Oil.

One approach to forecasting oil prices for DER BCA inputs is to use the U.S. EIA STEO forecasts for the first year or two of the study period, and then use the AEO forecasts for the remaining years. Forecasts from futures markets can be used for intermediate years and can also be used as a benchmark to check the AEO forecasts (see CME Group, Oil).

The oil price forecasts tend to be provided for a variety of different fuel grades. DERs might affect different grades of oils depending upon the customer and sector they serve. In general, the following fuel grades can be used to determine oil supply impacts associated with DERs:

- No. 2 grade is distillate fuel oil used in the residential sector.
- No. 4 grade is distillate fuel oil used in the other sectors.
- No. 6 grade is residual fuel oil used in the commercial, industrial, and electric sectors. (See AESC 2021, page 56.)

Note that customers in different regions of the country might use different fuel grades than those presented here. Consequently, these might need to be modified for those regions.

Price Forecasts for Other Fuels

U.S. EIA provides a variety of price forecasts for other fuels. The same methods described above for oil price forecasts can be used to prepare price forecasts for other fuels. In sum, short-term U.S. EIA forecasts can be used for the early years of the study period; long-term U.S. EIA forecasts can be used for later years in the study period; and alternative forecasts can be used instead of or as a benchmark for short- to intermediate-term forecasts (see CME Group, Oil).

For some types of other fuels, the U.S. EIA or alternative forecasts might not extend out through the full BCA study period. In these cases, the longer-term oil price forecasts can be used as an index to extrapolate the other fuel prices.

5.2.1.c. Resources For Calculating Other Fuel Supply Impacts

Avoided Energy Supply Components Study Group. 2021. (AESC 2021). *Avoided Energy Supply Components in New England: 2021 Report*. Prepared by Synapse Energy Economics, Resource Insight, Les Demans Consulting, Northside Energy, Sustainable Energy Advantage.

CME Group. n.d. (CME Group, Oil). "Crude Oil Futures and Options." cmegroup.com website. www.cmegroup.com/markets/energy/crude-oil/light-sweet-crude.quotes.html.

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5.3. Other Fuel Environmental Compliance Impacts

5.3.1.a. Definition

Overview of Other Fuel Environmental Compliance Impacts

Other fuel suppliers are sometimes required to incur costs for compliance with environmental requirements. Many such requirements are already included in other fuel prices impacts and therefore do not need to be calculated separately. GHG mandates are the primary environmental requirement that might need to be estimated separately for other fuels.

GHG mandates specify emission reductions relative to a benchmark amount (e.g., 1990 emissions) or sometimes place a cap on total emissions (as in cap-and-trade above). They sometimes limit emissions by a single target year (e.g., 2030), or sometimes limit emissions by increasing amounts for several target years (2030, 2040, 2050). Mandates are legally required, while targets are generally not legally binding. An example of a federal GHG target is the U.S. Nationally Determined Contribution, a 2030 emissions target submitted under the Paris Climate Agreement (See U.S. 2021 NDC).

Relationship to Societal Environmental Impacts

Societal environmental impacts are the impacts on the environment that occur in the absence of environmental requirements or after the environmental requirements have been met. It is important to distinguish between environmental compliance impacts and societal environmental impacts.[12]

- Environmental compliance impacts are the direct impacts in dollar terms that will be incurred by the utility and passed on to all customers through revenue requirements and customer rates.

[12] Societal environmental impacts are sometimes referred to as "environmental externalities." They are also sometimes referred to as "non-embedded" environmental impacts (AESC 2021).

- Societal environmental impacts are imposed on society as a whole but do not affect the cost of electricity services.

For further discussion see Section 3.2.6.

Anticipated Environmental Requirements

A BCA should account for all environmental requirements expected to be in effect over the study period (See RAP 2012; RAP 2013, pages 32-37). This should include requirements that are already established by statutes, regulations, orders, or other directives, even if they have not taken effect yet. If a particular requirement is expected to take effect in three years, for example, then the implications of that anticipated requirement should be applied in the third year of the BCA study period and beyond.

Similarly, BCAs should also account for environmental requirements that have not yet been established but are reasonably likely to be established within the study period. Environmental regulations often become more stringent over time (see RAP 2013, page 29) and failure to account for such changes will understate the actual environmental compliance costs.

> BCAs should account for all environmental requirements expected to be in effect over the study period, including those in place but not yet in effect, and those that are not in place but are likely to be in place during the study period.

There may be situations where it is not entirely clear whether environmental requirements will be imposed on other fuels. For example, a state might establish a GHG target, but the target is not a binding mandate, or the target is applied to the entire economy and not explicitly applied to other fuels. In these situations, stakeholders and regulators should estimate the most likely timing and magnitude of the targets on other fuels using the best information available. To completely ignore the GHG targets will understate the costs of compliance with them in the BCA.

There will inevitably be some uncertainty about anticipated environmental regulations, just as there is uncertainty about most of the impacts discussed in this MTR handbook. Risk assessment techniques can be used to address this uncertainty.

In the case of other fuels, the cost of compliance with *current* GHG emission mandates, if any, are likely to be included in the current prices and price forecasts for these fuels. Thus, the *anticipated* environmental requirements might be the only environmental compliance costs that need to be accounted for in this case.

5.3.1.b. Method for Calculating Compliance with GHG Mandates

To calculate the cost for other fuels to comply with GHG mandates, it may not be practical or appropriate to use the planning constraints or the GHG cost methods described above for electric and gas utility systems (see Section 3.2.6.b).

Further, for other fuels the only form of environmental compliance costs might be the compliance costs associated with *anticipated* environmental requirements because current environmental requirements are typically accounted for in the cost of the other fuels. In these cases, the best option might be to start with a value for the societal GHG impact and modify it to reflect the anticipated GHG requirements.

For example, in a situation where a state is expected to apply an economy-wide cap on GHG emissions, which requires a 10 percent reduction in GHG emissions by 2025 and increasing reductions until zero GHG emissions is reached in 2050, then the value for the societal GHG impact can be applying starting in 2025. The GHG compliance cost value for 2025 could be set to a portion of the total societal GHG impact, and then increase commensurate with the reduction in the GHG cap until it reaches the full societal GHG value by 2050.

Methods for calculating the dollar value of the societal GHG impact are discussed in Section 7.1.2.

5.3.1.c. Resources for Calculating Other Fuel Environmental Compliance Impacts

Regulatory Assistance Project. 2012. (RAP 2012). Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for 'Other Program Impacts' and Environmental Compliance Costs. T. Woolf et al., Synapse Energy Economics. www.synapse-energy.com/sites/default/files/SynapseReport.2012-11.RAP_.EE-Cost-Effectiveness-Screening.12-014.pdf.

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Smart Electric Power Association. 2021. (SEPA 2021). "Utility Carbon-Reduction Tracker™" sepapower.org website. sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/

United States Government. 2021. (U.S. 2021 NDC). The United States of America Nationally Determined Contribution—Reducing Greenhouse Gases in the United States: A 2030 Emissions Target. www4.unfccc.int/sites/ndcstaging/PublishedDocuments/United%20States%20of%20America%20First/United%20States%20NDC%20April%2021%202021%20Final.pdf.

5.4. Other Fuel Wholesale Market Price Effects

5.4.1. Definition

Wholesale market prices are a function of the demand of buyers and the marginal costs of suppliers. When DERs reduce (or increase) the demand for other fuels, they reduce (or increase) the wholesale market prices, which creates benefits (or costs) for all customers participating in the wholesale market. Even a very small perturbation of the market price can have large impacts when applied across all wholesale customers. This effect is sometimes referred to as demand reduction induced price effect (DRIPE).

Unlike electricity, but like gas, wholesale market price effects for other fuels are expected to persist for the life of the DER (see AESC 2021, page 233).

Other fuel wholesale market effects are likely to be considerably lower than those for electricity and gas because the impact on consumption of other fuels from DERs is likely to be very small compared with the national or international markets for those fuels.

5.4.2. Method for Calculating Wholesale Market Price Effects

For other fuels, the wholesale market price effect can focus on the oil markets. This will provide a value that can be used for oil, which can then be adjusted for other types of other fuels.

The other fuel wholesale market price effects can be calculated with the steps shown in Table 53.

Table 53. Steps for calculating other fuel wholesale market price effects

Step 1	**Estimate the wholesale gas price elasticity** This is the "price shift," which represents the change in gas price ($/MMBtu) for a change in gas demand (MMBtu). Oil play breakeven analyses can be used for this purpose. Oil play breakeven analysis "models the price at which a given geological formation is revenue neutral (a specific oil field or formation is known in the industry as a "play"). Different plays have different breakeven points, and when considered in aggregate, a supply curve can be made to show the prices at which various sources of new supply would enter the market. This curve can be thought of as analogous to an electric market's power plant offer stack" (see AESC 2021, pages 230-231).
Step 2	**Express the price shifts in terms of price-per-demand (in $/MMBtu of demand)** They can then be applied to any generic change in demand. This can be achieved by multiplying the price elasticities by total future market demand. The price-per-demand value can then be multiplied by a DER's anticipated savings to determine the wholesale market price effect.
Step 3	**Adjust the price-per-demand value** Adjust the value to account for market conditions that affect the magnitude of the wholesale market price effect.

5.4.3. Resources for Calculating Wholesale Market Price Effects

Avoided Energy Supply Components Study Group. 2021. (AESC 2021). *Avoided Energy Supply Components in New England: 2021 Report*. Prepared by Synapse Energy Economics, Resource Insight, Les Demans Consulting, Northside Energy, Sustainable Energy Advantage.

5.5. Delivery Impacts

Delivery costs for other fuels are typically included in the fuel prices. Therefore, they do not need to be calculated separately from the supply costs.

6. HOST CUSTOMER IMPACTS

The term "host customer" is used to refer to a utility customer that installs a DER in their home, business, or other type of property. The host customer might be a participant in a DER program, a customer who installs DERs with the assistance of a third party, or a customer who installs DERs in response to price signals.

Host customer impacts should be accounted for in a jurisdiction's BCA if they are relevant to the jurisdiction's energy policy goals, consistent with NSPM 2020 guidance. If accounting for host customer impacts is required, then ensuring symmetry in the treatment of host customer costs and benefits—even where hard to quantify—is critical to ensuring unbiased treatment in valuing any one resource relative to others. This includes accounting for host customer impacts for the full study period of the BCA. This chapter provides guidance on how to account for the range of host customer impacts, including hard-to-quantify impacts, for host customer energy and non-energy impacts.

Host customer impacts should be accounted for in a jurisdiction's BCA if they are relevant to the jurisdiction's energy policy goals, consistent with NSPM 2020 guidance.

6.1. Host Customer Energy Impacts

Examples of the main types of host customer energy impacts are provided in Table 54. These impacts can be either benefits or costs, depending on the situation or use case. In most cases, the host DER costs, any transaction costs, and any interconnection fees will represent costs to the host customers. For some of the impacts listed, such as risk or reliability, the impacts can be either a benefit or cost. See the NSPM 2020 for further guidance on when an impact may be a cost versus a benefit for different DERs and use cases.

Table 54. Host customer energy impacts

Type	Host Customer Impact	Description
Host Customer	Host customer DER costs	Costs incurred to install DERs (often offset by utility incentive)
	Host transaction costs	Other costs incurred to install DERs
	Interconnection fees	Costs paid by host customer to interconnect DERs to the electricity grid
	Risk	Uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error; this type of risk may depend on the type of DER
	Reliability	The ability to prevent or reduce the duration of host customer outages
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions
	Tax incentives	Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs
	Energy cost impacts	Costs or benefits associated with changes in energy costs

Additionally, there may be cases where an energy-related benefit or cost is experienced by the owner of a DER, as opposed to the host customer. For example, some distributed PV systems are owned by a PV third-party developer and leased to the host customer. In other instances, the DER is owned by a commercial or residential landlord, but the energy utilities are paid for by a tenant who is the host customer. In these cases, some or all of the costs or benefits of the DER are passed on to the host customer through some mechanism (e.g., lease payments, higher rent, lower energy bills, increased reliability, etc.). Consequently, a portion of the costs or benefits that are technically experienced by the third-party developer or landlord can be attributed to the host customer.

6.1.1. Host Customer DER Costs

6.1.1.a. Definition

Host customer costs include the incremental costs incurred to plan for, install, operate, and maintain a DER project. These are the costs of the DER incurred by the host customer relative to the cost of a standard measure or alternative consumer choice (referred to as the baseline costs or Reference Case) and after accounting for any utility or other incentives.

For example, in the case of some energy efficiency or electrification measures, the new technology replaces a less efficient, or fossil-fuel based option that the host customer would have obtained in the absence of the DER program or intervention. Here, the incremental cost of the measure is the difference in price between the DER and the baseline option.

In some cases, the incremental cost may be the total cost of the DER. For example, for a host customer who installs a new generation resource, such as solar PV, the baseline is often no new generation resource. In this example, the incremental cost of the DER is simply equal to the total cost of the DER.

For all DERs, any financial incentive provided to the host customer should be subtracted from the incremental DER costs for use in cost-effectiveness tests.

The incremental DER cost should include all costs throughout the BCA study period that are associated with planning and procuring the DER relative to the baseline option. Host customer costs can also occur in the form of a subscription cost that is paid over time to a third-party owner of a DER, as is often found with community solar projects.

Table 55 lists examples of costs to consider when calculating host customer DER costs. The cost elements apply to both DER and baseline options. Ideally, cost escalation should be considered for any ongoing costs, as relevant.

Table 55. Types of costs to consider when calculating host customer DER costs

Cost Element (Examples)		When Cost *May* be Applicable (Examples)				
		Large Construction Projects (New Buildings, Major EE Renovations)	DG and DS Projects; Commercial-Scale EV	Residential-Scale EV	Small-Scale EE and DR Retrofits	Residential Upstream and Commercial Midstream EE Programs
Materials and labor	Planning costs: Audits, feasibility studies and designs (not including the host transaction costs covered in Section 6.1.2)	✓	✓			
	Direct costs: Materials, supplies, equipment and labor for installation / construction of project	✓	✓	✓	✓	✓
	Indirect costs: Electrical upgrades or other construction needs as result of project	✓	✓	✓		
Other procurement	Permits, inspections, and other fees (not including the interconnection fees covered in Section 6.1.3)	✓	✓	✓		
	Sales tax (some states allow certain DERs to be exempt from sales tax)	✓	✓	✓	✓	✓
Ongoing costs related to procurement	Financing, including subsidized loans from the state, utility, or another organization	✓	✓	✓		
	Property tax increases (some states and municipalities exclude costs for certain DERs when assessing property values)	✓	✓	✓		
	Subscription costs		✓			

Note: EE = Energy Efficiency; DG = Distributed Generation; DS = Distributed Storage; EV = Electric Vehicle; DR = Demand Response.

6.1.1.b. Methods for Calculating Host Customer DER Costs

Conceptually, the host customer DER cost is calculated by simply subtracting any financial incentives from an electric utility (see Section 3.5.1) or other source from the incremental cost of the DER. However, in practice, determining the Host Customer DER cost can be a complex exercise for some types of use cases. Complexities relate to several factors, including the following:

- Collecting data for all of the cost elements in Table 55, especially for the baseline case since that represents the action not taken by the customer
- Taking into account escalation, cost of money (financing), and differences in project lifetimes between the DER and the baseline case
- Understanding and applying state- and jurisdiction-specific costs and incentives

Estimating costs is generally easier for DERs that are an add-on to a property than for DERs that substitute alternative energy technologies.

DER as "Add-On”

As described above, there are some DER use cases where the incremental cost is simply equal to the total DER project cost including any utility infrastructure or customer electrical upgrades over the lifetime of the DER. These special cases include installation of solar PV and/or battery storage at a host customer site for which there is no alternative distributed generation or storage option currently installed or being considered. They could also include demand response-enabling controls that are added to existing equipment.

DER as "Substitute”

For installation of demand response-ready technologies (e.g., grid-integrated water heaters) or implementation of energy efficiency or electrification measures (including electric vehicles, distributed generation, and distributed storage systems that displace fossil fuel-fired counterparts), determining the total incremental cost is much more complicated.

All of these examples substitute an alternative option with a DER, rather than introducing a new, add-on DER. A homeowner may be faced with a choice to purchase an efficient or inefficient refrigerator, but they are unlikely to opt out of owning a refrigerator altogether. *Given this distinction from the add-on use case, the total incremental cost of a DER in the substitute use case is the total incremental cost above a baseline (i.e., Reference Case) option.*

Incremental Cost Studies

The methods for preparing incremental cost studies can vary depending on the DER in question. In general, incremental cost studies often involve the following components:

1. Conducting in-depth interviews with installers, manufacturers, retailers, and other industry experts to:
    - Confirm the baseline option;
    - Define the DER boundaries (e.g., is ancillary equipment essential to the “typical” installation?);
    - Define the typical installation or more complex installation;
    - Identify any other special characteristics that might impact costs; and
    - Gather data on typical costs from the interviewees, as available (see Table 55 on costs elements to consider).
2. Collecting available DER cost data from program administrators, implementation contractors, and/or directly from host customers (if possible). Available data may be in the form of database extracts that compile costs for a group of customers, or it may consist of equipment invoices or purchase orders. For complex construction projects, more detailed unit pricing may be available. (Unit pricing involves preparing a “takeoff” listing of every element of the project from the project drawings and then itemizing material and labor costs.)
3. Estimating baseline cost data—and any missing DER cost data—using cost estimation resources. Some resources have data that show changing rates over time and geographical variations. Examples of sources include:

- RSMeans data website (see RSMeans)
- National Construction Estimator (see Pray 2021)
- Grainger website (see Grainger)
- U.S. Bureau of Labor Statistics (see U.S. BLS)
- Associated General Contractors of America (see AGCA)

In practice, jurisdictions often 'borrow' or use incremental cost data from other jurisdictions that have invested in studying incremental costs.

4. Verifying costs or filling in gaps using other publicly available resources:
   - Manufacturer and distributor websites
   - Cost studies (see U.S. EIA 2018, NREL 2021, and PNNL 2019)
   - Technical reference manuals (some include measure costs)
   - Measure work papers (e.g., from the California Public Utilities Commission)
5. Compiling and normalizing the cost data to provide a single analysis platform for each DER

In practice, jurisdictions often 'borrow' or use incremental cost data from other jurisdictions that have invested in studying incremental costs. Some examples of such studies are:

- Massachusetts' MA19R18: Residential New Construction Incremental Cost Update (see NMR 2020 MA19R18)
- Massachusetts' RLPNC 17-14: Mini-Split Heat Pump Incremental Cost Assessment—Final Report (see NMR Group. 2018)
- CPUC's *Measure Cost Studies* guide (see Itron 2015)
- Navigant's EM&V Forum *Incremental Cost Study* (see Navigant 2015)

The same general methods used to calculate host customer costs for traditional energy efficiency and demand response measures can be applied to electrification measures. A key difference is that the baseline technologies relative to the new electrification measures are likely to be non-electric measures (e.g., the baseline technology for evaluating electric heat pump water heaters is likely to be a natural gas- or propane-fueled water heater). Nonetheless, the incremental costs and subsequent host customer costs should be treated consistently based on the program delivery approach.

The total incremental cost of a "substitute" DER measure varies by program type and status of the alternative option because these factors will impact the definition of the baseline condition, and therefore the incremental cost. The standard practice for calculating the incremental cost is summarized below for the most common program types and baseline conditions: new construction and major renovation, replace on failure, early replacement, and retirement and removal.

New Construction and Major Renovation

For new construction and major renovation projects, the incremental cost of a DER is defined as the cost of the DER above what is required by building code or appliance standards (i.e., the baseline technology). For states without building codes or with outdated codes—or where common practices

Example: In Massachusetts, measure-level incremental costs for residential new construction programs are established in two ways. The primary source is from contractors who report how much more expensive building to program-level efficiency is compared to baseline efficiency homes. These results are then averaged with a second source, the incremental cost estimates from the National Renewable Energy Laboratory's (NREL) National Residential Efficiency Measures Database (NREMD). (See NMR Group 2020.)

(standard industry practices) exceed codes, the baseline technology may be developed through market surveys. New construction programs are designed to encourage builders and developers to go above and beyond what is required by codes and standards or to exceed common practice.

Replace on Failure

The replace on failure baseline occurs when a customer needs to replace their old equipment due to its failure or the fact it has reached the end of its useful life. It mostly applies to energy efficiency and electrification projects but could also apply to replacing distributed generation or storage equipment. In this situation, the customer must choose between purchasing a DER that is more efficient and/or has a lower carbon footprint than the alternative options on the market or purchasing one of the alternatives. Replace on failure programs are typically designed to move host customers to adopt more energy efficient or greener DER technologies. To capture this situation, the incremental cost should represent the cost of the new DER above the cost of the alternative equipment that the customer would have purchased in the absence of the subject program. Depending on the measure and jurisdiction, the baseline would either represent an applicable code or standard, or common practice.

Early Replacement

DERs that replace existing, functional equipment before the end of the equipment's useful life are defined as early replacement measures. Establishing the incremental cost of early replacement measures is complex for two reasons:

- Early replacement changes the timing of costs relative to when they could be incurred in the baseline scenario (i.e., absent the early replacement)—at least in cases where a jurisdiction chooses to include participant benefits and costs; and
- That change in timing can lead to the need to account for multiple baseline assumptions (assumptions that change over time) for both costs and savings.

The NSPM 2020 provides guidance on how to calculate the incremental cost of early retirement measures (see NSPM 2020, Appendix H2).

Retirement and Removal

Some utility programs encourage customers to remove their old equipment without replacement. For example, some program administrators offer refrigeration recycling programs where an incentive is offered to remove the old appliance. In this situation there is no incremental cost.

The calculation of the host customer cost for this type of program depends on the program's financial incentive. It is common for program administrators to pay 100 percent of the removal cost for this type of offering. In this situation there are no host customer costs. In the case where the program administrator does not cover 100 percent of the removal cost, the customer cost would be calculated by subtracting the utility incentive from the cost to remove the equipment.

6.1.2. Host Transaction Costs

6.1.2.a. Definition

This includes the transaction costs associated with the acquisition and installation of DERs. These costs can include time spent collecting information, obtaining quotes from multiple vendors, filing paperwork, and completing applications for rebates and other financing mechanisms. This impact will always be experienced as a cost for the host customer.

6.1.2.b. Method for Estimating Host Transaction Cost Impacts

Host transaction costs can be estimated on the basis of the host customer's "lost time," which can be valued using the hourly wage of the host customer, in the following steps:

Step 1 Estimate the hours of effort from a host customer

This is the number of hours that a host customer is expected to spend researching, acquiring, and installing the DER.

Step 2 Estimate the hourly wage of the person doing the work

This is the person most likely to research, acquire, and install the DER. For residential host customers, the median hourly wage of the region can be used. For commercial and industrial host customers the typical hourly wage for a staff person likely to research, acquire, and install the DER can be used.

Step 3 Calculate the transaction cost

Multiply the transaction hours (from Step 1) by the hourly wage (from Step 2).

These steps are summarized in the following formula:

$$\text{Host transaction costs} = (\text{hourly wage}) * (\text{number of hours for host customer to acquire and install DER})$$

6.1.3. Interconnection Fees

6.1.3.a. Definition

Interconnection fees are the costs associated with the utility and/or ISO/RTO interconnection process paid for by the host customer or a third party. Interconnection fees can include costs associated with permits, studies, grid upgrade costs assessed to the customer, or inspections.

Interconnection costs can be designated as a flat fee, a cost per installed capacity, or as a variable cost (e.g., $/MW) pending an assessment. Small DERs are more likely to have streamlined interconnection processes, whereas large projects may require detailed studies and extensive grid upgrades.

Interconnection costs may vary based on system size, whether the system is set up to export back to the grid, or whether multiple systems interact (e.g., PV plus storage).

6.1.3.b. Method for Estimating Interconnection Fee Impacts

Interconnection fees for DERs are set by the state, utility, and/or ISO/RTO. This information is best obtained through one of these entities, or a third party such as an installer that may pay for the costs on behalf of the customer. The DERs to which interconnection fees are the most applicable are solar PV and battery storage.

Solar PV

Most states have fixed application fees for small to mid-sized PV systems, while larger projects are more likely to be assessed on a $/MW basis. Table 56 below shows several examples of interconnection fees by state.

Table 56. State examples of interconnection fees for solar PV

State	Standard Fee	Supplemental Review
New Mexico	Fee is graduated by proposed system size: • $50 for systems ≤10 kW • $100 for systems 10 kW to 100 kW • $100 + $1/kW for systems larger than 100 kW	• Customer is responsible for utility costs of conducting the supplemental review
Utah	• $60 for simplified review	• Fast-track: $75 + $1.50/kW + review cost • Engineer review capped at $100/hr
Washington	Maximum application fee: • $100 for facilities 25 kW and smaller • $500 for facilities 26 kW to 500 kW • $1,000 for facilities 500 kW to 20 MW	• No supplemental review process

Source: NREL 2018.

Several states, including California and Colorado, require pre-application reports upon request that could lead to additional costs associated with interconnection.

Battery Storage

Battery storage systems are highly flexible grid resources that act as both sources of energy and consumers of energy. Battery storage can be installed as standalone systems or can be paired with solar PV. Many states have yet to define a specific interconnection procedure for battery storage. Depending on the state, battery storage systems may be categorized under the same set of regulations as solar PV and consequently have corresponding interconnection fees or be viewed as separate resources.

6.1.4. Risk, Reliability and Resilience

Host customer impacts from DERs can include direct benefits (or costs) with regard to risk, reliability, and resilience—depending on the DER(s) installed and the use case being evaluated. These impacts are addressed separately in Chapter 8 (Reliability and Resilience) and Chapter 10 (Risk).

6.1.5. Tax Incentives

6.1.5.a. Definition

Federal, state, and local tax incentives are sometimes available to host customers to defray the costs of some DERs. Tax incentives are deducted from a host customer's annual income tax and are typically presented as a percent of total project costs or as a fixed credit.[13]

[13] Many factors can influence the final monetary benefit of a tax incentive, including but not limited to individual or corporate tax liability, federal/state tax interplay, and refundable and non-refundable incentives. Program administrators may have to make some simplifying assumptions to capture the most likely final tax benefits to host customers.

The NSPM 2020 Appendix F (Table F-5) applies criteria to determine when tax incentives should be included in a cost-effectiveness test. If tax incentives are not an offsetting impact, they should be included. Based on the criteria, tax incentives should be included in the Total Resource Cost Test and Participant Cost Test as a benefit to the host customer, but they should not be included as a benefit or cost in the Utility Cost Test or Societal Cost Test. In jurisdiction-specific tests that include host customer impacts, tax incentives can be included as a benefit to host customers if that is consistent with the jurisdiction's energy policy goals.[14]

Federal Tax Incentives

Federal incentives for DERs vary between years. Incentives may decrease from year-to-year as market adoption increases or disappear altogether with changing federal priorities. Applicable federal tax credits for DERs may be obtained from the office of Energy Efficiency and Renewable Energy at the U.S. Department of Energy (See U.S. DOE O&M 2018). Table 57 reflects federal tax incentives for DERs at the time of this publication.

Table 57. Federal tax incentives

DER Type	Incentive	Primary qualifications
Solar PV and energy storage	Percent of total project costs: • Before 2019: 30% • 2020–2022: 26% • 2023: 22%	• Available for solar PV or solar PV and storage • Total project costs include PV panels/cells, contractor costs, balance-of-system equipment (wiring, inverters, etc.), associated energy storage devices, sales tax—netted with any utility incentives. • Residential energy storage systems must be charged exclusively by a renewable energy system to receive the full rebate. • Commercial energy storage systems will receive between 75% and 100% of the federal tax credit proportional to the percent of charge attributed to solar energy. Storage systems that charge with less than 75% solar energy are not eligible.
Electric vehicles	$2,500–$7,500	• Credits are allocated based on the make and model of the vehicle • Vehicles must be new • The electric motor must provide a significant portion of energy (>4kWh)

Source: U.S. DOE O&M 2018.

State Tax Incentives

Host customers may qualify for tax incentives offered by their state in addition to or independently from federal incentives. This can take the form of income tax incentives, sales tax holidays, and property tax incentives. Table 58 contains examples of state tax incentives available at the time of this publication.

[14] It is sometimes argued that, from a societal perspective, the benefit of the tax incentive is exactly offset by the cost to the taxpayers for the incentive, and therefore neither should be included in the BCA. While it is true that this benefit to the host customer is equal to the cost to the taxpayers, that does not mean that the tax incentive should be netted out against the cost. The tax incentive itself was clearly motivated by the policy goal of promoting the DER. If a jurisdiction shares that policy goal, then the tax incentive can be included in the BCA as a benefit to host customers. Otherwise, netting out this benefit will defeat the policy goal underlying the tax incentive.

Table 58. State tax incentives

State	DER Type	Incentive	Primary qualifications
New York	Solar PV	25% off solar PV system equipment expenditures, capped at $5,000	• Must be installed at principal residence • Must produce electricity for residential use
Maryland	Energy storage	30% of costs up to $5,000 for residential storage systems and $150,000 for commercial storage systems	• Storage must be for electric use and designed to offset energy at peak times • Total state funding for this tax credit is capped, meaning access to the credit is available on a first-come, first-served basis
Colorado	Plug-In Electric Vehicle	For purchase or conversion: range from $2,500 (light-duty PEV) to $10,000 (heavy-duty truck) For lease: range from $1,500 (light-duty PEV) to $5,000 (heavy-duty truck)	• Purchased vehicles must be new • Leased vehicles must have lease term of at least two years • Beginning in 2022, tax credits for purchased vehicles are reduced and tax credits for conversions end

Sources: New York State 2019; Maryland Energy Administration 2021.

6.1.5.b. Methods for Calculating Tax Incentive Impacts

Federal Tax Incentives

Federal tax credits reduce the amount of federal income tax owed by a host customer. Federal tax credits are either offered as a percent of project costs or as a fixed credit that does not vary based on the initial customer investment. For example, the federal solar energy investment tax credit (ITC) is based of a percentage of the cost of a solar PV system, while the federal electric vehicle tax credit provides up to a $7,500 credit for qualifying battery electric vehicles. See Figure 29 for a summary of methods to estimate impacts from federal tax incentives.

Figure 29. Summary of methods to estimate impacts from federal tax incentives

Federal % of Project Costs

- Determine current federal tax incentive (% project cost)
- Determine total DER project cost
- Determine utility incentives for host customer
- Subtract utility incentive from project cost to calculate net project cost (under most circumstances)
- Multiply federal percent incentive by net cost to calculate federal tax credits (in$)

Federal Fixed Tax Credit

- Total federal tax credit should simply be set to the fixed tax credit

Percent of Total Project Cost Method for Federal Tax Incentives

The percent tax credit should be multiplied by the project costs, as shown in Table 59. Applicable project costs include equipment costs, labor costs, and sales tax. Under most circumstances, utility incentives or rebates should be removed from the total project cost (see U.S. DOE Tax Guide).

Table 59. Steps to calculate federal tax incentives using the percent of total project cost

Step 1	Determine the federal tax incentive (in % of project cost) Use Table 57 above or updated versions of it.
Step 2	Determine the DER total project cost (in $) The total project cost should include equipment, labor, and sales tax costs.
Step 3	Determine the utility financial incentive offered to the host customer See Section 3.4.1.
Step 4	Determine the net project cost Subtract the utility financial incentive (from Step 3) from the total project cost (from Step 2).
Step 5	Calculate the federal tax credits (in $) Multiply the tax incentive (from Step 1) by the net project cost (from Step 4).

These steps are summarized in the following formula:

*Federal tax incentive = (total equipment costs + total labor costs + sales tax – utility incentives) * (percent federal tax incentive)*

State tax credits should not be factored into this calculation.

Fixed Tax Credit Method

Fixed tax credits are more straightforward because they do not differ with project cost. The total federal tax credit should simply be set to the fixed tax credit.

State Tax Incentives

The methods for calculating state tax credits largely mirror the methods for calculating federal tax credits. State tax credits, like federal credits, are either offered as a percent of project costs or as a fixed credit that does not vary based on the initial customer investment.

The methods for federal and state tax credits diverge slightly because of the interplay between federal and state taxes. By claiming a state tax incentive, a customer effectively increases their total income reported (by reducing the taxes owed). Consequently, the customer now reports a higher income to be taxed at the federal tax rate. This interplay modifies the calculation methods, as displayed in Figure 30 (See DOE Tax Guide 2021).

Figure 30. Summary of methods to estimate impacts from state tax incentives

State % of Project Costs	State Fixed Tax Credit
• Determine current state tax incentive (% project cost) • Determine DER project cost • Determine utility incentives for host customer • Subtract utility incentive from project cost to calculate net project cost (if required by state) • Multiply state percent incentive by net cost; then multiply result by one minus federal tax rate to calculate state tax credits (in$)	• Multiply state tax credit by one minus federal tax rate

Percent of Total Project Cost Method for State Tax Incentives

The calculation method for a state tax credit that is presented as a percent of project costs is nearly identical to the federal tax credit method, with the exception that the total tax refund is reduced by the federal tax rate. Table 60 describes those steps.

Table 60. Steps to calculate state tax incentives using percent of total project cost

Step 1	Determine the state tax incentive Express as a percent of project cost.
Step 2	Determine the DER total project cost (in $) The total project cost should include equipment, labor, and sales tax costs.
Step 3	Determine the utility financial incentive offered to the host customer See Section 3.4.1.
Step 4	Determine the net project cost Subtract the utility financial incentive (from Step 3) from the total project cost (from Step 2). This requirement may vary by state.
Step 5	Calculate the state tax credits (in $) Multiply the tax incentive (from Step 1) by the net project cost (from Step 4), and then multiplying the result by one minus the federal tax rate.

These steps are summarized in the following formula:

*State tax incentive = (total equipment costs + total labor costs + sales tax – utility incentives) * (percent state tax incentive) * (1 – federal tax rate)*

Fixed Tax Credit Method

The fixed tax credit method is modified identically.

*State tax incentive = (fixed tax credit) * (1 – federal tax rate)*

Federal and state tax credits are additive.

6.1.6. Energy Cost Impacts

6.1.6.a. Definition

DERs typically result in energy bill savings for the host customer. In some cases, such as electrification, the DER might increase the host customer's electricity bill but decrease the costs of other fuels such as natural gas or gasoline.

6.1.6.b. Application

Host customer bill impacts associated with the utility conducting the BCA should not be included as a benefit or cost in the BCA. Those host customer bill savings would overlap significantly with the utility system benefits, which are already accounted for in the utility system impacts in BCA tests. As such, including them in a BCA would double-count some of those impacts.[15] Further, host customer bill savings result in lost revenues, which can contribute to rate impacts, which should be analyzed separately from cost-effectiveness analyses (see NSPM 2020, Chapter 2, Section 4.4.3, and Appendix A).

> Host customer bill impacts associated with the utility conducting the BCA should not be included as a benefit or cost in the BCA….
>
> However, for DERs that have interactive effects with other types of energy sources it is appropriate to include bill impacts for the changes in consumption of the other energy sources.

However, for DERs that have interactive effects with other types of energy sources, it is appropriate to include bill impacts for the changes in consumption of the other energy sources. There are many examples of such DERs, including efficient lighting projects that increase the costs for oil heating, demand response programs that defer or increase back-up generation, distributed generation projects that require alternative fuels such as combined heat and power, building electrification, and electric vehicles). In these cases, the changes in consumption of the other energy sources should be accounted for as other fuel impacts (see Chapter 5).

In the case where a Participant Cost Test is used to help inform program design and financial incentive levels, host customer bill savings should be included. This is because the Participant Cost Test is designed to represent the actual impacts on host customers, including bill impacts from all relevant energy sources. In the Participant Cost Test, the energy cost savings are the primary benefits of DERs, but the utility system benefits are not included at all, thereby preventing double-counting.

6.1.6.c. Method for Estimating Host Customer Bill Impacts

Host customer bill impacts can be calculated by multiplying the DER energy impacts by the corresponding energy prices. For host customers with time-of-use rates, the DER's hours of operation should be mapped to the hourly time-of-use rates. For host customers with demand charges, the DER demand savings or generation (in kW) should be applied to the demand charges (in $/kW), in addition to applying the DER savings or generation to the energy charge. Ideally, the energy prices should be escalated through the life of the DER, or the length of the BCA study period.

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[15] Host customer bill savings are driven by the rates that the customer pays for generation, transmission, and distribution, which are typically based on historical embedded costs. Utility system benefits are based on future, incremental generation, transmission, and distribution costs. While embedded costs can be very different from incremental costs, there is nonetheless considerable overlap between the two.

6.1.7. Resources for Calculating Host Customer Energy Impacts

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6.2. Host Customer Non-Energy Impacts

Non-energy impacts (NEI) of DERs are real or perceived, financial or intangible, impacts not directly associated with energy production, transmission, distribution, or use. In some cases, the lines are blurry between what constitutes as an energy impact versus a non-energy impact. Therefore, NEI analysis may also be used to capture impacts that are not commonly recognized or quantified as energy impacts, even if they are associated with energy supply and demand (e.g., impacts on other fuel types, renewable energy credits, or power quality).

While often more difficult to quantify than direct energy impacts, there are multiple sources and methods for determining NEI values. On balance, researchers have found that NEIs have positive impacts for utility systems, consumers, and society, and they sometimes represent substantial benefits—for example, with respect to air quality and public health. Even from the lens of just the host customer, the impacts can be significant and may even equal or exceed the energy bill impacts. Moreover, those customer-level impacts can have a ripple effect throughout the economy, crossing over to areas far beyond just energy.

Considering whether and how to include NEIs is an important component of cost-benefit analyses—to the extent accounting for host customer impacts is a stated policy in a jurisdiction. Some NEIs are easier to quantify than others. Examples of more measurable impacts include water savings and reduced O&M costs, while harder to measure impacts include increased comfort and convenience. Nevertheless, it is better to use the best available approximation for a material impact than to assume it does not exist or that its value is zero.

Considering whether and how to include NEIs is an important component of cost-benefit analyses – to the extent accounting for host customer impacts is a stated policy in a jurisdiction. Some NEIs are easier to quantify than others.

6.2.1. Definition

DERs can create a variety of NEIs for host customers that are separate from the energy saved or produced by DERs. Table 61 presents a summary of host customer NEIs that might potentially be created by DERs. These impacts can sometimes be in the form of benefits and sometimes costs. NEIs can represent one-time benefits to participants, annual benefits to participants, or benefits based on total savings.

Table 61. Examples of host customer non-energy impacts

Host Customer NEI	Summary Description
Asset value	Changes in the value of a home or business as a result of the DER (e.g., increased building or property value, improved equipment value, extended equipment life, compliance with building codes)
Productivity, product quality, and O&M	Changes in labor costs, operational flexibility, O&M impacts (including impacts on other energy sources and water and wastewater costs as well as reduced maintenance (e.g., because of longer lives of LEDs)), increased production, improved product quality, reduced waste streams, reduced spoilage, etc.
Economic well-being	Economic impacts beyond bill savings (e.g., greater disposable income, reduced complaints about bills, reduced terminations and reconnections, reduced foreclosures—especially for low-income customers)
Comfort and convenience	Changes in comfort level (e.g., thermal, noise, and lighting impacts), greater convenience (e.g., smart technologies), loss of service (e.g., power disruptions from demand response event or loss of extra garage refrigerator to store additional food)
Health & safety	Changes in health and safety for host customers and building occupants (e.g., fewer sick days from work or school, reduced medical costs, improved indoor air quality, reduced deaths, reduced liability)
Empowerment & control	The satisfaction of being able to control one's energy consumption and energy bill
Satisfaction, pride, and sustainability goals	The satisfaction of helping to reduce environmental impacts (which is one of the reasons why residential customers install rooftop PV). The ability to meet corporate sustainability goals.

The presence, direction, and magnitude of these impacts will depend upon many factors, including the type of DER (e.g., energy efficiency, demand response, distributed generation, storage, electrification, electric vehicles), the specific DER technology (e.g., energy efficient lighting versus energy efficient building conditioning), the type of host customer (e.g., low-income, residential, commercial, industrial), whether the host customer values the impact, and the role of the host customer, potentially relative to a landlord or third-party developer.

NEIs for energy efficiency are much more thoroughly analyzed and used than NEIs for other DER types. NEIs for other DER types are still novel and often have limited supporting documentation. The following methods for calculating NEIs apply to all DER types but have historically been implemented for energy efficiency.

6.2.2. Methods for Calculating Host Customer Non-Energy Impacts

Host customers experience NEIs to varying degrees, and importantly, have varied perceptions of the exact benefits or costs of those NEIs. As with other estimates of DER and non-DER costs and benefits, regardless of the method used, some level of uncertainty will remain as to whether the chosen method accurately estimates the value of the NEIs experienced by customers. Both the accuracy and precision of NEIs vary based on the estimation method selected.

NEIs can be applied at the measure, measure-type, end-use, program, sector, or portfolio level. The more granular the assessment level, the more likely the NEIs are to accurately represent impacts experienced by participants.

Although some jurisdictions apply NEIs at the portfolio-level (as a percent adder), this fails to capture the variability of measure mix or customer types. For example, water savings apply only to measures that impact water use. If water benefits are applied at the portfolio level as an adder, they could be overstated for a project that has no connection to water savings, such as a large commercial lighting project. Applying NEIs at a more granular resolution reduces this risk.

Figure 31 summarizes several options for estimating NEIs. From a generalized perspective, the order of accuracy decreases from left to right. The calculation methods for each option are outlined below.

Figure 31. Summary of methods to estimate host customer non-energy impacts

Jurisdiction-Specific Studies	Transfer Values from Other Jurisdictions	Proxies	Accounting for Non-Monetized Impacts	Alternative Thresholds
• Conduct studies specific to the DER program region, using either customer surveys for targeted participants or NEI algorithms	• Identify existing jurisdiction studies that most closely reflect conditions in relevant jurisdiction • Determine which values are transferable • Account for any differences between jurisdictions in populations of interest (e.g., low income)	• Determine a percent adder to mutiply by total resource benefits • Apply at portfolio, sector, program, or measure level--but more granular is better • Proxies tend to vary by type of customer (e.g, low-income proxies tend to be higher than those for other residential customers)	• Relevant qualitative information can be used to estimate impacts that cannot be monetized • Develop qualitative explanation	• Pre-determine benefit-cost ratios (less than one) at which DERs will be deemed cost-effective • Establish and articulate before BCA process

Some NEI values would not be expected to vary by jurisdiction—for example, comfort. However, states use different methods, inputs, and assumptions to derive NEI values, and regulators exercise independent judgment in finalizing NEI values. Often, the NEI value represents a unique set of circumstances and cannot be directly transferred. The studies, however, usually provide methods that can be replicated. These methods range from relatively simple lookups of region-specific rates or costs that can be applied to the amount of energy, water, or resources saved, to conducting sophisticated studies or running sophisticated models that consider economic patterns and wages (see LBNL 2020 NEI).

Option 1: Jurisdiction-Specific Studies

Rigorous jurisdiction-specific studies on DER impacts potentially offer the most accurate approach for estimating and monetizing relevant impacts. Jurisdiction-specific studies are conducted specifically for the geographic region and market in which the DER program operates. As such, NEIs calculated using this option benefit from location- and market-specific inputs, direct feedback from participants, or other factors that improve the accuracy and precision of the results. There are two primary methods for jurisdiction-specific studies: customer surveys and NEI algorithms with jurisdiction-specific inputs.

Customer Surveys

Customers surveys are one approach evaluators use to estimate the value of a host customer NEI. These surveys often use a “relative valuation” method, by which surveys can ask host customers to estimate the dollar value of a series of NEIs as well as their annual bills savings to the best of their abilities. The bill savings can be used as a method to normalize the dollar values assigned to each NEI, given the potential for variability in responses (see Tetra Tech, NRM Group 2011).

A slightly modified approach is for participants to report added benefits as a percentage on top of bill savings. Utility-estimated bills savings may be appropriate to compare with customer-reported bill savings (see APPRISE Incorporated 2018). If studies find that a large portion of participants place little or no value on any particular NEI, that NEI should be discounted accordingly (see Tetra Tech, NMR Group 2011).

Table 62 below presents a simplified example of a relative valuation survey that could be used to estimate NEIs experienced by a single customer. In this example, the survey form asks a customer to estimate their bill savings from two distinct DERs (rooftop solar and a heat pump). Then the form asks the customer to estimate the impacts (in dollars) of two NEIs (comfort and empowerment/control) as a result of those measures. The estimated NEI as a percent of the estimated bill savings are calculated for each DER and NEI.

Table 62. Simplified example of relative valuation survey for estimating non-energy impacts for single customers

DER	Estimated bill savings ($)	NEI 1: Comfort		NEI 2: Empowerment/control	
		$	% bill savings	$	% bill savings
Rooftop PV	$500	$0	0%	$50	10%
Heat pump	$200	$10	5%	$0	0%

Note: the values in the table above are illustrative and do not necessarily represent actual savings or actual customer responses.

Another approach to customer surveys is the “willingness-to-pay” method, which asks customers to assign a dollar value to the amount they would be willing to pay for each NEI. This approach typically yields more conservative estimates for NEIs. Surveys sometimes include a hybrid approach with both the relative valuation and the willingness-to-pay methods to gain a more complete understanding of how customers value various impacts. One caveat with applying willingness-to-pay studies with low-income customers is that their values may be lower because their capacity to pay is lower, skewing results to appear as if they value benefits less than general customers.

For NEI surveys to be analyzed in aggregate, the surveyed population group should all have received the same measure type(s) in order to isolate the benefits. For example, if a study intends to quantify an NEI for hot water measures, the participants should have all received hot water products (see APPRISE Incorporated 2018). In many cases, participants may have received more than one measure from the program administrator.

If participants received more than one measure type, they should be separated into a distinct group that received the same measure types. Surveys can be distributed to a sampling of program participants who are meant to represent the total population served. The larger the number of participants, the more statistically viable (see APPRISE Incorporated 2018).

It is important to note that responses from these types of customer surveys are often associated with high uncertainty—and the uncertainty itself is also difficult to quantify. But, as noted earlier, using even approximations to estimate the impacts is better than assuming they have no value. Further, surveys should be conducted on a periodic basis in order to capture the most up-to-date opinions.

Using even approximations to estimate host customer impacts is better than assuming the impacts have no value.

NEI Algorithms

Jurisdictions can develop or repurpose algorithms to calculate NEIs based on territory-specific inputs. Not all NEIs are well suited to algorithms, such as changes in comfort. But others may have clear and jurisdiction-specific inputs.

Two common examples are natural gas and water impacts from electric efficiency measures; these are both relatively easy to quantify and often prescribed with algorithms in technical reference manuals. The value of the energy and water impacts can be quantified by multiplying them by applicable utility rates.

Some other examples include (see Skumatz et. al. 2019):

Reduction in allergy symptoms

> *Reduction in allergy symptoms = (number of children with environmentally attributed asthma) * (direct medical cost of asthma in children) * (estimated reduction in asthma from program for host customers)*

Fewer fires

> *Fewer fires = [(average property loss from fires per incident) * (percentage of incidents resulting from products offered in the portfolio) * (estimated percentage of incidents that could be fixed with new equipment) * (percentage of households receiving relevant equipment) * (percentage of fires eliminated based on program's efforts)] + [(average number of injuries/deaths per household) * (percentage of incidents resulting from products offered in the portfolio) * (value of loss of life) * (percentage of households receiving health and safety measures) * (percentage of fires eliminated based on program's efforts)]*

O&M impacts from repairs and repair costs

> *O&M savings/costs = (average number of appliances that could experience a change in O&M costs)* ***** *(appliance repair rate)* ***** *(change in repair frequency from the newer equipment)*

In cases where the equation inputs are not well defined or not readily available, DER program administrators may need to rely on a blended approach to quantifying NEIs in which the inputs to the calculations are based on survey results.

Low-Income NEI Considerations

Customer surveys and NEI algorithms can also be used to determine low-income NEIs. For both approaches, it is important that the study represent only the low-income population as defined by the program. For customer surveys, this relates to the sample population surveyed. For the NEI algorithms, this relates to the inputs.

> **Example:** Xcel Energy conducted a low-income NEI study to monetize nine NEIs that could apply to its territory: reduced asthma, heat stress, cold stress, missed days from work, predatory loans, reduced fire risk, carbon monoxide poisoning, reduced utility disconnects, and increased food security. Xcel took a blended approach of surveys and NEI algorithms to quantify the designated NEIs (see Three Cubed 2020).
>
> Below are two examples of Xcel's monetization approach for low-income host customers in Minnesota. Both relied on algorithms where the inputs were based on survey results:
>
> <u>Household NEI – Missed days of work</u>
>
> *Missed days of work NEI = (% of weatherized LI households with an employed primary wage earner) * (reduction in missed days) * (average hourly wage) * (7.5 hours/day) * (% low-income workers without sick leave in MN)*
>
> <u>Household NEI – Reduced need for predatory loans</u>
>
> *Reduced need for predatory loans NEI = (average loan amount, by loan type) * (% reduction in households using loans, by loan type) * (average monthly interest rate of 25%)*

Option 2: Transfer values from Other Jurisdictions

Some NEI values or methods may be transferred between jurisdictions under the right circumstances. This option allows jurisdictions to benefit from detailed studies conducted elsewhere without having to fund the studies themselves. The applicability and ease of transferability varies by NEI and differences between jurisdictions. This process to determine whether an NEI can be transferred from another jurisdiction should start with a literature review that explores different values and methodologies used in the source jurisdictions' analyses (see LBNL 2020 NEI).

In some cases, precise values can be transferred from one jurisdiction to the next. This requires that the inputs used to calculate the NEI do not vary by jurisdiction. Exercise caution with inputs that relate to average home size, average income, average fuel costs, climate, or other variables that are likely to fluctuate based on location or market. In general, studies from nearby jurisdictions are more likely to be a good fit, given the relationship to weather that exists for many DERs (see LBNL 2020 NEI).

> **Example:** Rhode Island's energy efficiency program administrator applies residential and low-income NEIs from a Massachusetts study in its cost-effectiveness test. Rhode Island and Massachusetts have similar climates, landscapes, fuel prices, and energy efficiency programs, providing favorable conditions to transfer NEIs from one jurisdiction to another (see NEEP 2017).

In cases where a value cannot be suitably transferred due to jurisdictional differences, a jurisdiction could replicate a particular method while updating just the inputs that vary by jurisdiction.

Low-Income NEI Considerations

The option of transferring values from other jurisdictions can be used for low-income NEIs, but it is important to account for any differences between jurisdictions in the low-income populations that might affect the NEIs.

Option 3: Proxies

Proxies are simple, quantitative values that can be used as indirect indicators for values not monetized by conventional means. They can be applied to any type of benefit or cost that is hard to monetize and is expected to be of significant magnitude.

Proxy values should ideally be based on the best, most quantitative information currently available regarding the specific NEI and how it will be affected the DER being evaluated. Even with the best information available, however, it is sometimes necessary to rely upon professional judgment to make a rough estimate. In many cases, these rough estimates are then negotiated among relevant stakeholders to determine a reasonable proxy. Steps include:

1. Review literature on the NEI.
2. Quantify the NEI to the extent feasible.
3. Review proxy values in other jurisdictions.
4. Consider the conditions specific to the jurisdiction where the proxy will be applied.

Several types of proxies can be used to account for impacts:

- *Percentage "Blanket'" Adder*: A percentage adder approximates the value of non-monetized impacts by scaling up all impacts that are monetized. For example, the percent adder could be multiplied by the total resource benefits. This type of proxy is the simplest and easiest to apply but is a blunt tool. Several states apply this approach.
- *Energy Savings Multiplier* ($/MWh or $/MMBtu or X%): A savings multiplier approximates the value of non-monetized benefits or costs relative to the quantity of energy savings. For example, increasing value of benefits by 50 cents per MWh saved or by 10% of the value of the energy savings.
- *Customer Adder* ($/customer): A customer adder (or subtraction) approximates the value of non-monetized benefits relative to the number of customers served by a program.
- *Measure Multiplier* ($/measure): A fixed dollar amount adder—for example, $X.X per PV system.

Proxies may be used to reflect several types of NEIs at once. However, proxies will be more accurate if they are determined separately for each type of NEI.

Similarly, proxies can be applied at the portfolio, sector, program, or measure level. They will be most accurate if they are applied at the most granular level possible, to reflect the different magnitudes of NEIs at different levels.

The proxy method is the most commonly used approach for calculating NEIs (see DSP 2021). This is due more to the simplicity of the method than the accuracy. Other more comprehensive methods can be complex and expensive.

Example: In the District of Columbia, NEIs for the DC Sustainable Energy Utility Programs are calculated as a 5 percent adder, representing benefits from comfort, noise reduction, aesthetics, health and safety, ease of selling/leasing a home or building, improved occupant productivity, reduced work absences due to illness, avoided moves, and macroeconomic benefits (NMR 2020 DCSEU).

Low-Income NEI Considerations

The use of proxies also applies to low-income NEIs. Low-income proxies tend to be higher than those for non-low-income customers. This is because low-income customers typically experience higher benefits from DERs due to higher levels of energy burden, the condition of low-income housing stock, and social-equity-related concerns. See additional considerations on accounting for energy equity in Chapter 9.

Example: In Nevada, a higher proxy value is applied to low-income energy efficiency participants than non-low-income participants. Nevada uses a 10 percent adder for non-energy benefits for commercial participants, a 15 percent adder for non-low-income residential participants, and a 25 percent adder for low-income participants (see NPC and SPPC 2019).

Additional low-income benefits can exist for individual DERs as well.

Example: The District of Columbia applies an NEI proxy of 15 percent for low-income customers who install rooftop solar PV, as opposed to the 5 percent NEI adder calculated for non-low-income customers (NMR 2020 DCSEU).

Option 4: Use Non- Dollar Values for NEIs

This option allows DERs with benefit-cost ratios of less than one to be deemed worthwhile based upon qualitative considerations of NEIs (see NSPM 2020, Appendix C). These qualitative considerations need to be described in order to justify the cost-effectiveness of the DER.

This approach requires a qualitative explanation as to why the relevant NEIs are large enough for the DER to be deemed cost-effective despite a low benefit-cost ratio. In some regards, this makes for a more transparent accounting of the NEIs. In general, this flexible approach is highly subjective and rarely applied on a portfolio-wide scale.

Accounting for non-monetary impacts involves several steps:

- First decide *whether* to include impacts in cost-effectiveness tests based on the relevant policies, goals, regulations, and relevance of specific NEIs. Then decide separately *how* to value or otherwise account for the impacts.
- Provide as much quantitative evidence as possible.
- Establish metrics to create quantitative data for future analyses that can result in quantitative values.
- Provide as much qualitative evidence as possible.
- Decide on the implications of the quantitative and qualitative evidence.
- Non-monetized impacts are presented alongside monetary impacts so regulators can compare the monetized, quantitative, and qualitative factors and evidence to decide whether a program is appropriate.

- Document and justify the decision.

Low-Income NEI Considerations

Qualitative assessment of non-monetary impacts is commonly used for low-income NEIs. This option can be used to justify low-income programs that are not deemed cost-effective when it is difficult to quantify and monetize NEIs. As noted above, qualitative considerations require a more transparent accounting of the low-income NEIs.

> **Example:** In Ohio, the Public Utility Commission states that a utility can offer programs or measures that are not cost-effective if it can demonstrate enumerated non-energy benefits. Accordingly, this provides utilities with programmatic flexibility (DSP 2021).

Option 5: Alternative Thresholds

Alternative thresholds are another option for addressing hard-to-monetize impacts. They allow DERs to be deemed cost-effective at pre-determined benefit-cost ratios that are less than one (See NSPM 2020, Appendix C). Applying a proxy value can essentially have the same effect as using alternative benchmarks.

Alternative thresholds are, by design, a simplistic way of recognizing that the hard-to-monetize impacts are significant enough to influence the cost-effectiveness analysis. The primary advantage of this approach is that it does not require the development of specific monetary or proxy values. The disadvantage is that it might not eliminate DERs that are more costly than necessary. This disadvantage can be mitigated through sound DER program design.

Regulators should ensure that alternative thresholds are as transparent as possible and are established prior to the cost-effectiveness analysis. Ideally, regulators should articulate which resources the alternative thresholds can be applied to, what the threshold is, and the basis for the threshold chosen.

Low-Income NEI Considerations

The alternative thresholds option is often used for low-income NEIs. In the case of low-income NEIs, a benefit-cost ratio threshold of less than one can be used to account for the non-energy benefits of DERs hosted by low-income customers. Some jurisdictions that place a high priority on protecting low-income customers do not require low-income DER programs to be subject to a BCA, which is essentially equivalent to dropping the benefit-cost ratio threshold to zero (see NESP 2021 DSP).

6.2.2.a. Summary of Methods for Calculating Host Customer Non-Energy Impacts

The advantages and disadvantages of the different methods available to estimate host customer impacts is provided in Table 63.

Table 63. Advantages and disadvantages of methods for estimating host customer non-energy impacts

Method	Description	Advantages	Disadvantages
Jurisdiction-Specific Studies	Studies conducted specifically for the geographic region and market in which the DER operates	The most accurate option	Can be expensive and time-consuming to conduct and apply
Transfer Values from Other Jurisdictions	Using values from other jurisdictions, in select cases where there is sufficient consistency across jurisdictions	Can be reasonably accurate; requires much less time and effort than jurisdiction-specific studies	Can be applied only to programs, measures, customers, and other conditions that are consistent across jurisdictions
Proxies	Simple, quantitative, rough approximations, based on as much quantitative data as possible combined with professional judgment	Simple; easy to understand and apply	Much less accurate than other options; consequently, jurisdictions tend to adopt low proxies to reduce the risk of overstating the impact
Qualitative Consideration	Allowing DERs to be considered cost-effective on the basis of benefits that are justified using qualitative information only	Simple; allows for flexibility in programs that provide unique benefits	Requires a separate assessment alongside the monetary results of BCA; can result in non-cost-effective investments
Alternative Thresholds	Establishing benefit-cost ratio thresholds that are less than one to support DERs that have important qualitative benefits, such as low-income benefits	Simple	Provides no information on the value of low-income NEIs; if less than 1.0, can result in non-cost-effective investments

6.2.3. Resources for Calculating Host Customer NEIs

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7. SOCIETAL IMPACTS

Electric and gas utility resources can have a variety of impacts that extend beyond the utility system and the host customer. Some or all of these societal impacts should be accounted for in a jurisdiction's BCA if they are relevant to the jurisdiction's energy policy goals, consistent with NSPM 2020 guidance. Table 64 summarizes societal impacts commonly associated with DERs.

Societal impacts should be accounted for in a jurisdiction's BCA to the extent they are relevant to the jurisdiction's energy policy goals, consistent with NSPM 2020 guidance.

Table 64. Common societal impacts of DERs

Societal Impact	Description
GHG Emissions	GHG emissions created by fossil-fueled energy resources
Public Health	Health impacts, medical costs, and productivity affected by health
Other Environmental	Other air emissions, solid waste, land, water, and other environmental impacts
Economic and Jobs	Incremental macroeconomic development and job impacts
Energy Security	Related to cybersecurity and/or energy independence
Resilience	Resilience impacts beyond those experienced by utilities or host customers
Energy Equity	Poverty alleviation, environmental justice, reduced home foreclosures, etc.

This chapter provides guidance on those societal impacts considered to be most significant and are often addressed in DER BCAs. Note that reliability and resilience impacts, which can have a societal dimension, are addressed separately in Chapter 8. In addition, energy equity, which can have a societal dimension, is addressed in Chapter 9.

Some of the societal impacts in Table 64 overlap with or are similar to utility system or host customer impacts. One example is GHG emissions, which might be partially accounted for as a utility system environmental compliance impact and partially as a societal impact. Another example is the public health benefits of DERs, which may accrue directly to host customers in the form of improved respiratory health (e.g., reduced asthma due to weatherization and/or ventilation measures) or can accrue broadly to society due to improved outdoor air quality from reduced emissions of criteria pollutants. Consequently, it is important to ensure that such benefits are not double counted in a BCA.

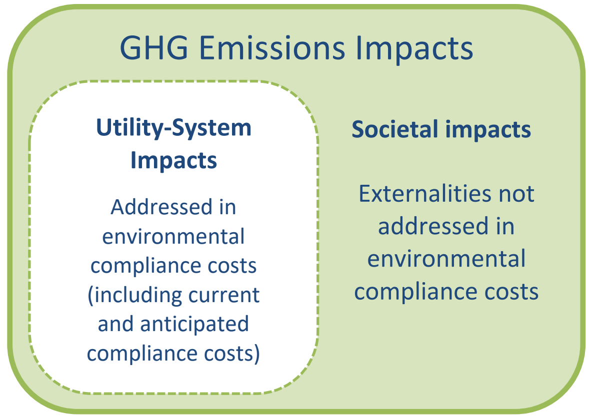
7.1. Greenhouse Gas Emission Impacts

7.1.1. Definition

Greenhouse gases include carbon dioxide, methane, nitrous oxide, and fluorinated gases. GHG emissions are created from a variety of sources, including production, transmission, and distribution of both electricity and natural gas; industrial processes; heating of commercial and residential buildings; and transportation.

Some DER types, such as distributed PV, can reduce GHG emissions by reducing the production and consumption of fossil fuels. Other DER types, such as building electrification and electric vehicles, can increase GHG emissions from electricity generation but reduce GHG emissions by reducing the consumption of other fuels such as gas or gasoline. For these latter DER types, it is important to account for net impact of increased and decreased emissions.

Figure 32. Distinction between societal and utility-system GHG emissions impacts



It is important to distinguish between societal GHG impacts and GHG environmental compliance impacts (see Figure 32 and Section 3.2.6.a). Societal GHG emissions represent the emissions that occur *after* compliance with GHG regulations and requirements. These societal emissions are referred to as "externalities" because the impacts are external to the monetary prices of the goods that create them. The costs of compliance with GHG requirements, on the other hand, are considered "internal" costs because they are passed on to customers in electricity prices.

For example, the cost of compliance with GHG cap-and-trade programs are utility system costs that can be monetized on the basis of the GHG allowance prices (see Section 3.2.6). Any environmental impacts that might result from any *remaining* GHG emissions are not passed on to utility customers in any way, and therefore should be considered societal impacts.

Distinguishing between environmental compliance (i.e., utility system) impacts and societal impacts: This distinction is important for two reasons. First, if a jurisdiction chooses not to account for societal GHG impacts in a cost-effectiveness test, then it is important that the GHG compliance impacts are properly calculated and included in the utility system impacts. Otherwise, the compliance costs incurred by utility customers will be left out of the analysis. Second, if a BCA is accompanied by a rate, bill, and participant impact analysis (see NSPM 2020, Appendix A), then it is important that the GHG compliance impacts are properly accounted for in that analysis because these impacts will be passed on to utility customers and will affect electricity and gas rates.

GHG emissions are often categorized as one of three scopes (See WRI 2015).

- Scope 1 includes emissions directly emitted from on-site combustion of fuels by an electric or gas utility customer. For example, a gas energy efficiency resource can reduce or avoid GHG emissions from the host customer's on-site combustion of natural gas. As another example, electric vehicles can reduce consumption of internal combustion engines vehicles.
- Scope 2 includes emissions associated with the production of electricity, steam, heat, or cooling. For example, a distributed PV resource can reduce or avoid GHG emissions from the regional power plants.
- Scope 3 includes emissions that are the result of activities from assets that are not owned or controlled by the utility or the host customer, e.g., the emissions associated with an electric or gas utility's contractors.

Together, all three scopes comprise what is often referred to as life-cycle emissions. It is especially important to calculate impacts for both Scope 1 and Scope 2 GHG emissions, because a decrease in Scope 1 emissions (from on site) is often accompanied by an increase in Scope 2 emissions (from power plants), and vice versa. Scope 3 emissions include the life-cycle emissions associated with manufacturing or disposing of electricity and gas infrastructure, including DERs.

Natural gas or refrigerant leaks could fall into either Scope 1 or Scope 2 depending on the timing, location, and type of leak.

7.1.2. Methods for Calculating Societal GHG Emission Impacts

Societal GHG emission impacts can be estimated using the steps shown in Table 65.

Table 65. Steps to calculate societal GHG impacts

Step 1	Determine the energy saved or generated (in MWh) by the proposed DER This can be developed using the proposed DERs' load impact profiles (see Chapter 11). Ideally, the energy saved or generated would be estimated on an hourly basis, to reflect the variation across different time periods with different marginal emission rates.
Step 2	Determine the marginal emission rate (in tons/MWh) Methods for determining marginal emission rates are described below under Step 3.
Step 3	Calculate the change in GHG emissions (in tons) This step is described further below.
Step 4	Determine the societal cost of GHG emissions (in $/ton) This step is described further below.
Step 5	Calculate the societal cost of GHG emissions (in $) Multiply the change in GHG emissions (from Step 3) by the societal cost of GHG emissions (from Step 4).
Step 6	Calculate net societal cost of GHG emissions (in $) Subtract GHG compliance costs, if any, from the societal cost of GHG emissions (from Step 5).

Steps 3 and 4 are described in detail below. Steps 1, 2, 5, and 6 are relatively straightforward calculations based on the previous steps.

Step 3: Calculate the Change in GHG Emissions (in tons)

The magnitude of GHG emissions is often presented in either metric tons (e.g., tonnes) or short tons (e.g., US tons). This handbook uses the term "tons" generically throughout for brevity. In practice it is important to use consistent units throughout any calculation of GHG emissions. Metric tons can be converted into short tons, and *vice versa*, using the following conversion factor: 1.0 metric tons = 1.10231 short tons.

Methods for Calculating GHG Emissions from On-Site Combustion (Scope 1)

GHG emissions from on-site combustion that may be affected by DERs include:

- GHG emissions from natural gas, propane, or oil combustion, when DERs reduce or increase on-site consumption of these fuels for space- or water-heating.
- GHG emissions from gasoline or diesel internal combustion engine vehicles when these are replaced by electric vehicles.

Building End-Use Emissions

Building end-use emissions refers to emissions that are produced on site by generating electricity or heating/cooling with fossil fuels, such as natural gas, oil, or propane. Table 66 describes how to calculate the reduction in building end-use GHG emissions from DERs.

Table 66. Steps to calculate reduction in building end-use GHG emissions from DERs

Step 1	Determine the annual energy consumption (in MMBtus) without DER This is the energy used by the end-use for a typical host customer in the absence of the DER being evaluated (see Chapter 11).
Step 2	Determine the annual energy consumption (in MMBtus) with DER This is the energy used by the end-use for a typical host customer after the DER being evaluated is operational (see Chapter 11).
Step 3	Calculate the change in consumption caused by the DER (in MMBtus) Take the difference between the consumption with and without the DER.
Step 4	Determine GHG emission factors (in tons/MMBtu) for the relevant fuel type This would be factors for natural gas, propane, oil, etc. (See U.S. EPA website, GHG Emission Factors.)
Step 5	Calculate the GHG emission impact (in tons) Multiply the change in consumption caused by the DER (from Step 3) by the carbon dioxide emissions factor for the fuel type (from Step 4).

Some DERs might affect both a change in consumption at the building end-use (Scope 1) and a change in production at the system level (Scope 2). In these cases, it is important to calculate both impacts.

Vehicle Emissions

Table 67 describes how to calculate the reduction in GHG emissions from electric vehicles.

Table 67. Steps to calculate reduction in GHG emissions due to electric vehicles

Step 1	Determine annual fuel consumption (gallons of gasoline or diesel) of the internal combustion engine vehicles to be replaced by the electric vehicles Fuel consumption will equal the typical vehicle-miles traveled by the vehicle (in miles) divided by the efficiency of the vehicle (in miles/gallon). (See U.S. EPA website, Alternative Fuels Data Center, for Information on fuel consumption of internal combustion engine vehicles.)

Step 2	**Determine the annual energy consumption (in gallons) used by the electric vehicle** In many cases, this will be zero. Hybrid electric vehicles will result in some fuel consumption. Fuel consumption for hybrid electric vehicles will equal the typical vehicle-miles traveled by the vehicle (in miles) divided by the efficiency of the vehicle (in miles/gallon). (See U.S. EPA website, Alternative Fuels Data Center, for information on fuel consumption of electric vehicles.)
Step 3	**Calculate the change in fuel consumption caused by the electric vehicles (in gallons)** Take the difference between the fuel consumption with and without the electric vehicles. This calculation should assume the same vehicle-miles traveled in each case, unless there is good reason to assume otherwise. The fuel consumption for the case without the electric vehicles should be based on the fuel efficiency and consumption of the typical vehicle that is being displaced by the electric vehicle.
Step 4	**Determine GHG emission factors (in tons/gallon) for the internal combustion engine vehicle being displaced** The U.S. EPA provides emissions factors for both gasoline and diesel internal combustion engine vehicles (see U.S. EPA GHG Emission Factors 2022).
Step 5	**Calculate the GHG emission impact in (tons)** Multiply the change in fuel consumption caused by the electric vehicles (from Step 3) by the GHG emissions factor for the internal combustion engine vehicle (from Step 4).

It is important to also calculate the increase in emissions from the purchase of electricity to power the electric vehicle.

Methods for Calculating GHG Emissions from Power Plants (Scope 2)

The change in GHG emissions from power plants (in tons) caused by DERs can be estimated by multiplying the change in consumption from the DERs (in MWh) by the marginal GHG emissions rates of the electricity system (in tons/MWh).

Marginal emission rates should be based on the electricity generators in the region where the DER will be located because rates can be very different for different regions. Further, marginal emission rates should ideally be determined on an hourly basis because they can change significantly as the marginal electricity generator changes throughout the day (see Section 2.6.) In other words, the hourly change in consumption from the DERS (in MWhs) should be "mapped onto" the hourly marginal emission rates (in tons/MWh).

BCAs should ideally use long-run, as opposed to short-run, marginal emission rates (see Section 2.7.2). Long-run marginal emission rates will capture the changes to emission rates that occur as a result of existing power plants retiring and new electricity resources being added to the system. Marginal emissions rates are expected to change significantly over the coming decades as the electricity system is increasingly powered by renewable generation. In other words, long-run marginal emissions rates may be very different from the short-run emissions of today or those of the next five years. These changes to the electricity system should be accounted for when calculating marginal emission rates over the BCA study period.

There are several sources of marginal GHG emissions rates available to the public, listed below. The U.S. EPA AVERT model and eGRID model provide only short-run marginal emissions rates. If the model used does not estimate long-run marginal emission rates, then it will be necessary to use other sources or to develop an independent forecast to determine those (see AESC 2021).

- NREL Cambium model. Cambium is a tool that assembles structured data sets of hourly cost, emissions, and operational data for modeled futures of the U.S. electric sector with metrics designed to be useful for long-term decision-making. Cambium was built to expand the metrics reported in NREL's Standard Scenarios—an annually released set of projections of how the U.S. electric sector could evolve across a suite of different potential futures, looking ahead through 2050 (see NREL Cambium). Specifically, workbooks are available for long-run marginal emission rates at: www.data.nrel.gov/submissions/170. Cambium is the only model listed here that provides long-run marginal emission rates.
- U.S. EPA AVERT model. AVERT is an open-access tool offered by the U.S. EPA to estimate the hourly emissions benefits of energy efficiency and renewable energy policies and programs. AVERT allows users to measure avoided emissions of carbon dioxide, sulfur dioxide, and nitrogen oxides resulting from state or multi-state programs. Stakeholders and regulators can also use the tool to identify likely generation units and regions impacted by different efficiency or renewable energy programs. The tool tracks each fossil unit's generation, heat input, and emissions and how they change under different user-entered policy scenarios. It can also identify likely changes in regional emissions when units are retired, replaced, or retrofitted with pollution controls. AVERT uses public data reported to the EPA by power plants in the United States. (See U.S. EPA AVERT.)
- U.S. EPA eGRID model. The Emissions & Generation Resource Integrated Database is a comprehensive source of data from EPA's Clean Air Markets Division on the environmental characteristics of almost all electric power generated in the United States. The data includes emissions, emission rates, generation, heat input, resource mix, and many other attributes. eGRID is typically used for GHG registries and inventories, carbon footprints, consumer information disclosure, emission inventories and standards, power market changes, and avoided emission estimates. (See U.S. EPA eGRID 2021.)
- Other tools. See U.S.EPA 2018, pages 4-42 through 4-56, for descriptions and links to a variety of tools to estimate emissions reductions from power plants.
- ISOs. Some ISOs and RTOs publish marginal emission rates for their electricity system. (See ISO-NE 2021, NY-ISO 2021.)
- AESC 2021. This report includes marginal emission rates for carbon dioxide and nitrogen oxides for electric generators and for non-electric fuels in New England (see AESC 2021, pages 364-368).

Methods for Calculating GHG Emissions from Leaks

GHG emissions can result from leaks in the gas and electricity systems. This can include natural gas (methane) leaks associated with the distribution of natural gas and refrigerant (fluorinated gases) leaks in cooling equipment, such as residential, commercial, and industrial refrigerators and heat pumps (see CPUC 2020).[16] Methane and fluorinated gases have high global warming potential (GWP), meaning they have a disproportionately high impact on global warming.

Calculating the magnitude of methane leakages from the distribution and consumption of natural gas involves multiplying GHG emissions from gas end-uses by leakage adders. One leakage adder should be

[16] Methods for calculating refrigerant leaks are not addressed in this handbook. For guidance on how to estimate refrigerant leaks, see CA ACC 2020, pages 79-81.

used for upstream gas production (gas production, processing, transportation, and delivery) and a separate leakage adder for downstream gas consumption (behind-the-meter usage).[17]

Table 68. Steps to calculate GHG emissions from leaks

Step 1	**Calculate the GHG emissions** The first step is to calculate the magnitude of building end-use GHG emissions (in tons) that are expected to be reduced or increased by the DER being evaluated. The method for this calculation is described above in this section (see: Methods for Calculating GHG Emissions from On-Site combustion; Building End-Use Emissions).
Step 2	**Identify Gas Leakage Rates** For methane, leakage rates can be calculated separately for upstream and downstream leakage. Leakage rates represent how much methane is leaked relative to how much is consumed (combusted)—though it is important to note that the leakage is not directly related to the combustion. The leakage rate is therefore in units of mass of leaked methane divided by units of mass of combusted methane. These have been studied and calculated at both national and state-specific scales. A combination of national and state-specific leakage rates may be appropriate depending on where the natural gas is produced. The U.S. EPA provides estimates of methane emission leaks from the U.S. gas industry. These estimates include leaks from various sources, including gas production, processing, transportation, storage, and delivery. The U.S. EPA also breaks out the leaks in terms of those from combusted, vented, and fugitive emissions (see U.S. EPA 2020, Tables 3 and 4). Leakage rates are available for both upstream and downstream leakages. The U.S. EPA notes that lost and unaccounted for gas is often used as a surrogate for gas losses but might not be appropriate for determining methane leakage rates. It claims that lost and unaccounted for gas is likely to overstate actual methane leaks because it is "merely an accounting term subject to numerous errors including gas theft, variations in temperature and pressure, billing cycle differences, and meter inaccuracies" (see U.S. EPA 2020, page 3). On the other hand, other studies indicate that the U.S. EPA results for methane leakage might be too low (see Alvarez 2018; Zhang et. al. 2020). **Example:** The Massachusetts Department of Environmental Protection requires that Massachusetts gas distribution companies report pipeline milage by age and material type, which in turn is used to estimate the potential leakages in the system. The Department then uses the reported milage and number of leaks to estimate tons of carbon dioxide per mile per year for each type of pipeline (e.g., cast iron, unprotected steel, etc.). This is done by multiplying the estimated leaks per mile by the emissions rate, which varies by pipeline type and making necessary unit conversions. (See MA DEP 2021, spreadsheet in Appendix C.)
Step 3	**Identify Gas Leakage Adders** The leakage rate is converted to a leakage adder using a selected GWP of methane and a mass conversion constant to convert methane to an equivalent value of carbon dioxide. The GWP is a value that was developed to describe the potency of a GHG relative to carbon dioxide. Figure 33 presents the process used for converting methane leakage to a leakage adder. The U.S. EPA provides GWP ranges for various GHGs, including methane, nitrous oxide, and fluorinated gases (see U.S. EPA GWP). As indicated in Figure 33, below, leakage adders should be developed for both upstream (leaked) and downstream (consumed) leakages. Leakage adders are available from some publicly available sources (see CPUC 2020, page 76).

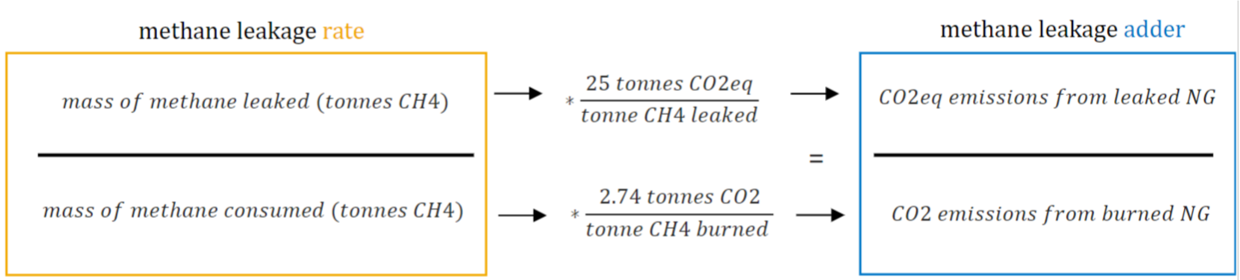
[17] Note that upstream leakage rates should represent marginal, not average, leakage rates because DERs will affect marginal leakages.

Step 4 Calculate the Magnitude of Leakage

The final step involves multiplying the DER's impact on GHG emissions from gas end-uses (from Step 1) by the leakage adders (from Step 3). For calculating upstream methane leakage, the GHG emissions should be multiplied by the upstream leakage adder. For calculating downstream methane leakage, the GHG emissions should be multiplied by the upstream leakage adder and the downstream leakage adder because leakage occurs both upstream and downstream.

For DER programs that reduce gas consumption but do not eliminate it, the downstream adder is zero because those end-uses will continue to leak gas. This means that, in general, the GHG emission impacts from gas energy efficiency resources should be multiplied by only the upstream leakage adder, while GHG emission impacts from building electrification measures should be multiplied by both the upstream and the downstream adder.

Figure 33. Process for converting methane leakage rate to a leakage adder



Source: CPUC 2020, page 75.

Step 4: Calculate the Cost of GHG Emissions in ($/ton)

There are two primary approaches for determining the cost of GHG emissions in $/ton: the social cost of carbon approach and the marginal abatement cost approach. Both approaches yield a value in units of dollars per ton of GHG emissions avoided.

Option 1: Social Cost of Carbon Method

The SCC method (also called the "damage cost" or "damage function" method) is based on the dollar value of the net cost to society from adding an incremental amount of that GHG to the atmosphere in a particular year. Costs include the net impacts to agricultural productivity, human health effects, property damage from flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of impacts to ecosystems (see U.S. IWG 2021).

Starting in 2008, U.S. federal agencies began regularly estimating the SCC, calculated by an interagency working group (IWG) of experts. Since 2016, the IWG has also estimated the social cost of methane and nitrous oxides. The IWG published an updated set of values for all three types of GHGs in 2021 (see U.S. IWG 2021).

The IWG values are not the only SCC values available. Many estimates have been made by different studies around the world. The IWG SCC values were derived in part by reviewing those other studies and developing values that are appropriate to use by U.S. federal agencies. As such, they are a credible, reasonable source for the purposes of BCAs for DERs.

The value of the SCC is sensitive to many factors, including the choice of model or models to use, damage functions, forecasts of population growth, macroeconomic development, climatological changes, uncertainty analyses, and more (see U.S. IWG 2021, pages 32-35). The models used for this purpose often forecast impacts out to the year 2300, which clearly will involve a great deal of uncertainty. Two factors that are especially important are the perspective of the damages considered (inclusive of damages globally, or only inclusive of damages locally) and the discount rate used to calculate present value dollars (see U.S. IWG 2021; AESC 2021). Thus, while the IWG report presents only a few streams of values for the SCC (one stream for each discount rate) this simple presentation masks the many uncertainties in the analysis and potential range of actual values of damage costs of GHG emissions.

The value of the SCC is sensitive to many factors, including the choice of model or models to use, damage functions, forecasts of population growth, macroeconomic development, climatological changes, uncertainty analyses, and more.

The IWG report presents SCC values for several different discount rates, thus it is necessary to choose a discount rate that is most appropriate for the jurisdiction that the BCA is conducted for. Many experts recommend using a societal discount rate (i.e., 1 to 3 percent) for this purpose (see U.S. IWG 2021; AESC 2021).

Information on the SCC, including information on which climate change impacts are accounted for in the SCC, which states currently use the SCC for planning purposes, and a calculator for calculating the SCC given user-selected parameters, is available on the Institute for Policy Integrity website (see IPI 2021).

Once the SCC value has been determined, the societal GHG impact (in $) can be determined by multiplying the SCC value (in $/ton) by the change in GHG emissions (in tons). Finally, the *net* societal GHG impact can be determined by subtracting the GHG compliance costs (see Section 3.2.6.b) from the societal GHG impact.

Option 2: Marginal Abatement Cost Method

The societal cost of GHG emissions can be estimating by identifying the carbon abatement option that is most likely to be the *marginal* option needed to address climate change. The marginal abatement option is determined by ranking all the potential abatement options from lowest to highest cost (in $/ton of GHG abated) and identifying the last, i.e., marginal, abatement option needed to reduce GHG emissions to a level that achieves societal climate change goals (i.e., net zero GHG emissions by 2050).

A marginal abatement cost curve is a way to identify the marginal abatement option. An MAC curve compiles all the relevant abatement options in a step function format to allow for prioritization of options based on cost-effectiveness. Figure 34 presents an example MAC curve. Each block in the curve represents a GHG abatement option, which in this case are different DER options. The width of each block indicates the magnitude of emissions that can be abated by that DER (in tons). The height of each block indicates the cost of each option, using levelized costs (in $/ton).

Levelized costs are used for this purpose because they allow for direct comparison of abatement options that have different operating characteristics and lifetimes. The levelized cost of an energy resource, or a carbon abatement option, represents the full cost of installing and operating the resource over its lifetime, in terms of a single value that applied to each year of the lifetime results in a cumulative present value that is the same as the cumulative present value of the actual stream of annual costs.

Levelized Costs: Levelized costs for electricity generation resources are commonly referred to as the levelized cost of electricity (LCOE) (see EIA 2019). Levelized costs for efficiency resources are commonly referred to as levelized cost of saved energy (LCSE) (see LBNL 2018 LCOE). This handbook uses the term "levelized cost of energy" to refer to both LCOE and LCSE interchangeably.

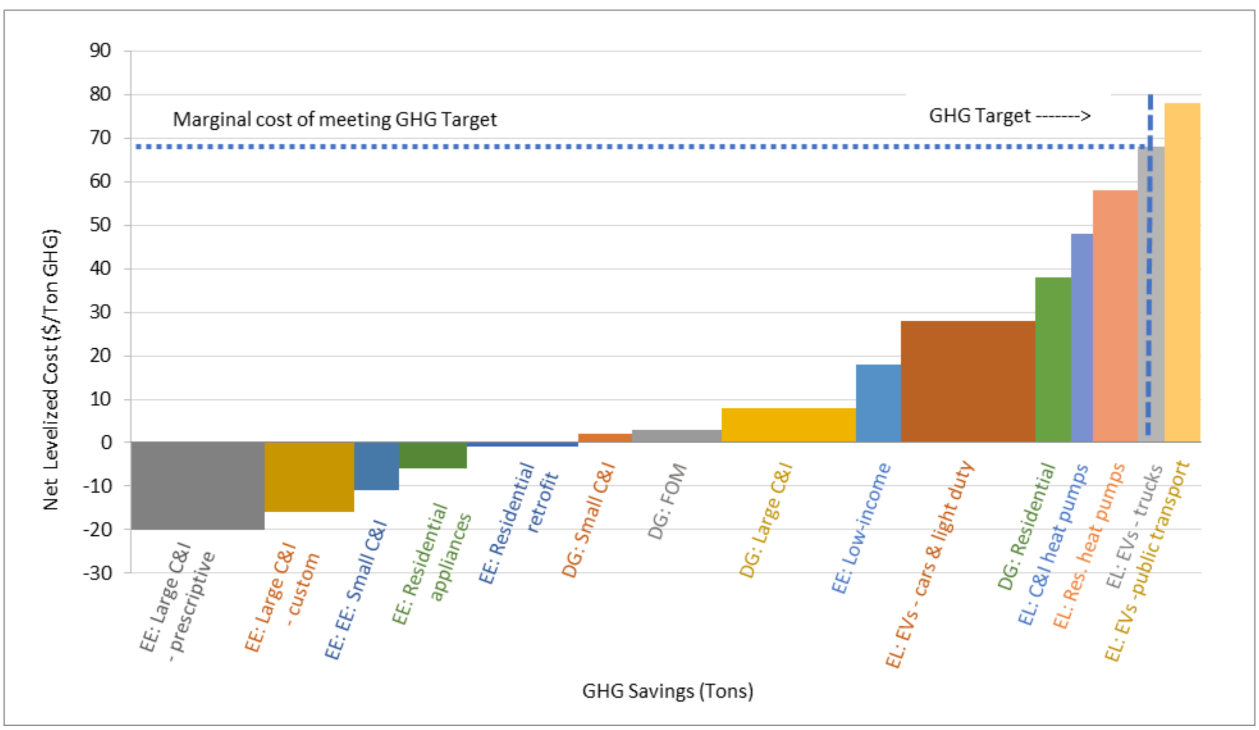
Publicly available sources. Levelized costs of electricity resources are available from several public sources, including (see Lazard 2021; LBNL 2018 LCOE; U.S. EIA 2021).

Independent estimates. Levelized costs can be calculated for specific resources using the following formulas:

> *LCOE = (capital recovery factor) * (resource lifetime costs) / (annual generation, in kWh)*
>
> *LCSE = (capital recovery factor) * (resource lifetime costs) / (annual electricity savings, in kWh)*
>
> *Capital recover factor = [r*(1+r)^n] / [(1+r)^n-1]*
>
> *r = the discount rate*

MAC curves present the cost of each GHG abatement option in *net levelized costs*. The net levelized cost is equal to the levelized cost of the abatement option, minus all the levelized benefits of the option, except for the GHG benefits. In this way, MAC curves indicate the GHG abatement cost of each abatement option, beyond all the other costs and benefits of that option (see NSPM 2020, Section 15.5.3).

Figure 34. Example marginal abatement cost curve for DERs



Source: Adapted from NSPM 2020, page 13-6, Figure 13-2. The DERs and cost-effectiveness results presented in this figure are purely illustrative and not based on specific DERs in a specific jurisdiction. Actual cost-effectiveness results could be significantly different from those presented here. In addition, actual results will differ depending upon the cost-effectiveness test used.

An abatement option with a net levelized cost below zero is cost-effective without considering the GHG benefits. For those abatement options with a net levelized cost above zero, the cost shown represents only the cost of abating GHG emissions. Presenting the net levelized costs in this way allows for straightforward comparison of many different types of abatement options from many different sectors.

MAC curves are especially useful for calculating the cost of complying with GHG mandates and requirements (see Section 3.2.6.b) because they can be tailored to the specific GHG mandates and requirements of the relevant jurisdiction. They can also be used for calculating societal GHG impacts.

If the marginal abatement cost approach is used to develop the *societal* impacts of GHGs, then the GHG target should represent a societal abatement goal, e.g., net zero GHG emissions by 2050. If the GHG abatement options used to develop the MAC curve are not sufficient to achieve this societal goal, then the curve will not reveal the full cost necessary to meet that goal.

If the marginal abatement cost approach is used to develop the *societal* impacts of GHGs, then the GHG target should represent a *societal* abatement goal, e.g., net zero GHG emissions by 2050.

The MAC can be developed for a given year using a selected carbon dioxide reduction amount. The MAC can be calculated differently based on the region of interest, e.g., global, national, regional, state, local. The MAC can also be calculated differently for the sector of interest, e.g., electric, gas, transportation, industry, others. Ideally, the MAC would include all sectors of the economy to provide a more complete picture of how a jurisdiction might be able to reduce GHGs. For example, if the MAC is being used as a GHG cost for both Scope 1 and 2 emissions, then both Scope 1 and Scope 2 abatement technologies should be included in the curve.

One of the most prominent MAC curves is the McKinsey curve, which considers costs and investments on a global scale (see McKinsey n.d.). Other attempts at making a MAC curve aim to include the impact of behavioral change (see Gillingham and Stock 2018) and using energy optimization models and systems-level analysis (see EDF 2021). New England’s AESC calculates a global and regional marginal abatement cost of carbon. At the regional level, AESC calculates an electric-sector-specific value as well as a value for all sectors (see AESC 2021).

MAC curves can be created using the steps in Table 69 below.

Table 69. Steps to calculate GHG emissions costs using a marginal abatement cost curve

Step 1	Put each DER cost into levelized terms These can be obtained from publicly available sources or by using formulas to calculate levelized costs using jurisdiction-specific information (see Section 3.2.6.b). This will provide costs in terms of levelized $/MWh.
Step 2	Put each DER benefit into levelized terms These are calculated the same as the costs. In this case, public sources are not likely to be available so the levelization formulas should be used (see Section 3.2.6.b). This will provide benefits in terms of levelized $/MWh.

Step 3	**Calculate the net levelized cost** This requires subtracting the levelized benefits (from Step 2) from the levelized costs (from Step 1). This will provide net benefits in terms of levelized $/MWh.
Step 4	**Calculate the net levelized cost per ton of GHG** This step involves first multiplying the net levelized costs of each DER (in $/MWh, from Step 3) by the amount of energy saved or generated by the DER (in MWh) to calculate the total cost of reducing that number of GHG emissions (in $) by that DER. Then the total cost of reducing GHG emissions from each DER (in $) should be divided by the total GHG emissions from each DER (in tons) to calculation the net levelized cost per ton of GHG (in $/ton).
Step 5	**Create a MAC graph** For a MAC graph, the vertical axis presents the net levelized cost of each DER (in $/ton GHG) and the horizontal axis presents the amount of potential GHG savings (in tons GHG) from each DER. The DERs should be ranked in order from lowest net levelized cost per ton on the left to the highest on the right.
Step 6	**Identify the marginal abatement cost** The marginal abatement cost is determined by identifying the point on the MAC curve where the "curve" of abatement options intersects with the GHG abatement target (see Figure 34). This point on the curve indicates the most expensive abatement option necessary to meet the GHG target, which represents the marginal abatement cost.

Comparison of Societal Cost of Carbon and Marginal Abatement Cost Methods

The primary advantage of the SCC method is that values for carbon dioxide, methane, and nitrous oxide are readily available for use and were developed by global experts and vetted by multiple U.S. federal agencies. Because the SCC values take a global approach, they can be used in any jurisdiction worldwide. Furthermore, the SCC can be applied to emissions from any sector because its calculation is not related to the origin of the emissions. However, there is considerable uncertainty underlying many aspects of the SCC estimates and these estimates are highly sensitive to many factors, some of which are highly contentious.[18]

The primary advantage of the marginal abatement cost approach is that it is tailored to the specific GHG goals of the jurisdiction. This makes it especially useful for estimating the cost of compliance with GHG mandates that are less stringent than a societal GHG goal. Further, the MAC indicates the actual costs that might need to be incurred to achieve a GHG target, while the SCC focuses on *damage costs* that might have little bearing on what *abatement costs* will be incurred. The MAC approach might be less uncertain than the SCC because it is based on known costs of known technologies that can abate emissions to the level desired in the jurisdiction. However, marginal abatement cost values often include considerable uncertainty, will vary by jurisdiction, and can be resource intensive to develop and use.

[18] One of the more obvious factors affecting the magnitude of the SCC is the discount rate. For example, the SCC for 2020 is estimated to be either 49, 116, or 390 $/ton, depending upon whether a discount rate of 3%, 2%, or 1% is used, respectively (AESC 2021, page 179). However, there are many other, less obvious, assumptions that have significant implications for the magnitude of the SCC, including the choice of models used, the inputs to those models, and the interpretation of the model results (Ackerman 2008).

In practice, a simple comparison of the SCC and MAC methods is difficult to make. First, developing the cost of GHG using *both* methods might be unduly expensive and time-consuming. Second, there is considerable uncertainty involved in using either of these methods; thus making a comparison of the two can be highly uncertain.

Further, the SCC is an average value for the entire world. There are likely to be some jurisdictions where the marginal costs of abating GHG emissions to desired levels are higher or lower than other jurisdictions. This means that two jurisdictions could have very different marginal abatement costs but have the same SCC. For this reason, it might be best to use the MAC values when they are available.

Example: The recent New England AESC study estimated GHG values in several different ways. First, it estimated the SCC to be $128/ton, assuming a 2% discount rate (AESC 2021, page 178-179). Second, it estimated the *marginal abatement cost* for the *electricity sector alone* to be $125/ton, based on the assumption that offshore wind is the most likely marginal GHG abatement option for the New England region (AESC 2021, pages 181-183). Third, it estimated that the *marginal abatement cost* for the *gas sector alone* to be $493/ton, based on the assumption that renewable natural gas is the most likely GHG abatement option for the gas industry in New England (AESC 2021, pages 184-186). While the first two estimates suggest that the SCC and the MAC methods lead to the same result, this is more a matter of coincidence. Simply choosing a different discount rate for the SCC would indicate that these two methods lead to very different results. More importantly, the marginal abatement cost for the gas industry shows how the SCC can understate the true cost of GHG emissions and shows the importance of considering all sectors that contribute to GHG emissions.

In sum, both the SCC and the MAC methods involve a great deal of uncertainty and care should be used when determining which approach is best for a jurisdiction. Table 70 provides a summary of these two different methods.

Table 70. Comparison of societal cost of carbon and marginal abatement cost methods

Method	Description	Applications	Advantages	Disadvantages
Social Cost of Carbon	Based on future global damage costs from climate change	1. For determining the total social cost of GHG emissions 2. For determining the cost of compliance with GHG mandates that require meeting a societal GHG goal, e.g., net zero emissions by 2050	• Values are readily available • Values are credible because they were developed and vetted by global experts and federal agencies • Can be applied to emissions from any sector • Does not require a specific carbon reduction target	• Involves considerable uncertainty and debate about future damage costs • Value is extremely sensitive to the discount rate chosen and complex modeling assumptions • Can only be used to determine total social cost of GHG emissions
Marginal Abatement Cost	Based on cost of technologies and other options that can be used to abate GHG emissions to a desired level in the jurisdiction of interest	1. For determining the total social cost of GHG emissions, if a societal GHG goal is used, e.g., net zero emissions by 2050 2. For determining the cost of complying with specific GHG targets	• Well-suited for determining the cost of compliance with GHG targets that are less stringent than a societal GHG goal • Based on known technologies with known costs relevant to the jurisdiction • Reveals the actual costs that might need to be incurred to meet GHG target	• Requires concrete emission abatement targets • Values not easily available; estimates are complex and resource-intensive • Ideally requires analysis for multiple sectors (electric grid, building, transportation, industry)

7.1.3. Resources for Calculating Greenhouse Gas Emission Impacts

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7.2. Public Health Impacts

7.2.1. Definition

Energy production and consumption can result in a variety of pollutants that can impact public health, including air emissions, solid waste, and liquid emissions. Air emissions from energy resources tend to cause the most significant public health impacts, so this section focuses on the public health impacts of air emissions from energy resources.

The primary air emissions from energy resources include nitrogen oxides, sulfur dioxide, particulate matter (e.g., $PM_{2.5}$), ozone, carbon monoxide, volatile organic compounds, mercury, and lead. These emissions have several implications for the health and well-being of affected populations, including premature death, chronic and acute bronchitis, non-fatal heart attacks, respiratory or cardiovascular hospital admissions, upper and lower respiratory symptoms, asthma, and asthma-related hospital visits (see U.S. EPA 2018).

Some DER types, such as distributed PV, can reduce air emissions by reducing the production and consumption of fossil fuels. Some DER types, such as distributed generators powered by fossil fuels, can increase air emissions by increasing fossil fuel consumption. Other DER types, such as building electrification and electric vehicles, can increase air emissions from electricity generation but reduce air emissions by reducing the consumption of other fuels such as gas or gasoline. For these latter DER types, it is important to account for net impact of increased and decreased emissions.

It is important to distinguish between societal air emission impacts and environmental compliance impacts (see Section 3.2.6.a). Societal air emissions represent the emissions that occur *after* compliance with air emission regulations and requirements. These societal air emissions are referred to as "externalities" because the impacts are external to the monetary prices of the goods that create them. The costs of compliance with air emission requirements, on the other hand, are considered "internal" costs because they are passed on to customers in electricity prices.

For example, the cost of compliance with sulfur oxides and nitrogen oxides cap-and-trade programs are utility system costs that can be monetized on the basis of the sulfur oxides and nitrogen oxides allowance prices (see Section 3.2.6). Any public health impacts that might result from any *remaining* sulfur oxides and nitrogen oxides emissions are not passed on to utility customers in any way, and therefore should be considered societal impacts.

Distinguishing between environmental compliance (i.e., utility-system) impacts and societal impacts: This distinction is important for two reasons. First, if a jurisdiction chooses not to account for societal public health impacts in a cost-effectiveness test, then it is important that the GHG and criteria pollutant compliance impacts are properly calculated and included in the utility system impacts. Otherwise, the compliance costs incurred by utility customers will be left out of the analysis. Second, if a BCA is accompanied by a rate, bill, and participant impact analysis (see NSPM 2020, Appendix A), then it is important that the GHG and criteria pollutant compliance impacts are properly accounted for in that analysis because these impacts will be passed on to utility customers and will affect electricity and gas rates.

It is important to avoid double-counting of societal GHG impacts and public health impacts.

- Estimates of GHG impacts that are based on *damage cost estimates*, such as the U.S. IWG SCC (see Section 7.1.2), typically include public health impacts as a part of the "damage" created by climate change. Therefore, when those values are used for GHG emissions, estimates of DER public health impacts should not include any public health impacts from climate change; they should include only those caused by other air emissions.
- Estimates of GHG impacts that are based on *marginal abatement costs* (see Section 7.1.2) can include the public health impacts of climate change, but only if the marginal GHG abatement cost is based on achieving a societal goal, e.g., net zero GHG emissions by 2050. If this goal is achieved through carbon abatement options, then in theory there will be no public health impacts of climate change.[19] If the marginal GHG abatement cost is based on a GHG goal that is less stringent than this societal goal, then in theory there will be public health impacts result from climate change that are not accounted for in the GHG impacts.

7.2.2. Methods for Calculating Public Health Impacts from Air Emissions

This MTR handbook provides a general method for calculating public health impacts from air emissions, as well as a shortcut that can be used for emissions from electricity generation. Figure 35 summarizes these methods.

[19] There have already been public health impacts of climate change to date, due to the severe weather events exacerbated by climate change. Nonetheless, the theory behind the marginal abatement cost approach is that if the societal goal of reducing GHG emissions is achieved, the vast majority of future climate change impacts, including public health impacts, can be prevented.

Figure 35. Methods for calculating public health impacts from air emissions

General Method	Benefit per kWh Method (Electricity)
• Determine energy saved or generated by proposed DER using load impact profile • Quantify the air emission impacts • Calculate changes in air quality by estimating trajectory of air emissions plume and determining affected populations • Quantify public health impacts of changes in air quality • Determine dollar values of those health impacts • Calculate health impacts per unit of energy consumption	• Using U.S. EPA's developed values of public health benefits associated with each kWh of electricity generation: • Establish energy impact of the DER (in kWh) • Calculate dollar value of the health impact (in $) by multiplying energy impact (in kWh) by BPK (in $/kWh)

Option 1: General Method

In general, calculating public health impacts from air emissions includes the following basic steps (see EPA 2018, Section 4.2; U.S. EPA 2021, page 10).

Step 1 Determine the energy saved or generated by the proposed DER

The energy saved or generated by the DER (in MWh or MMBtu) can be determined using the proposed DER's load impact profile (see Chapter 11). Ideally, the savings or generation would be developed on an hourly basis to reflect the variation across different time periods.

Step 2 Quantify the air emission impacts

This step requires calculating the air emission impacts associated with the energy saved or generated by the proposed DER (in tons/MWh, tons/MMBtu, or tons/gallon of gasoline).

For air emissions related to energy generation, this step involves determining the magnitude of marginal air emission rates on the system (see Section 2.7). Several public sources are available to determine marginal air emission rates for the region of interest (See U.S. EPA website, Air Emission Factors). Also see Section 3.2.6.b.

For air emissions related to electric vehicles, this step first requires calculating the gallons per year of gasoline from internal combustion engine vehicles that are avoided by the electric vehicle. Then the number of gallons should be multiplied by the air emission factors for either gasoline or diesel, to yield the tons of air emissions per year avoided by the electric vehicle. The U.S. EPA provides emissions factors for both gasoline and diesel (see U.S. EPA website, Air Emission Factors and Section 3.2.6.b).

Step 3 Calculate the changes in air quality

This step involves estimating the trajectory of the plume of air emissions and determining the populations that are most likely to be affected by them. The U.S. EPA offers two models that can help with this step, as described below.

Step 4 Quantify the public health impacts of those changes in air quality

This step involves estimating the likely health impacts on the affected populations, including mortality, morbidity, and air quality related hospital visits. The U.S. EPA offers two models that can help with this step, as described below.

Step 5	**Determine the dollar values of those health impacts** This step involves converting the health impacts from Step 4 (e.g., morbidity, mortality, and hospital visits) into dollar values. The U.S. EPA has established dollar values that can be applied to these health impacts. In addition, the U.S. EPA offers two models that can help with this step, as described below.	
Step 6	**Calculate the health impacts per unit of energy consumption** The dollar values from Step 5 can be divided by the DER energy saved or generated from Step 1 to produce health impacts per unit of energy consumption ($/MWh, $/MMBtu, $/gallon of gasoline). These results can then be applied to the energy impacts of the DER being evaluated (in MWh, MMBtu, or gallons) to determine the value of public health impacts (in $).	

The U.S. EPA has built two models that can help with Steps 3, 4, and 5:

- Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA). COBRA is an open-source health impacts screening and mapping tool developed and maintained by the U.S. EPA. It uses county-level inputs on changes in criteria pollutants to estimate impacts on public health, including morbidity and monetized health effects (See U.S. EPA COBRA). Website: www.epa.gov/cobra
- Environmental Benefits Mapping and Analysis Program – Community Edition (BenMAP-CE). BenMAP is s an open-source computer program developed and maintained by the U.S. EPA. It calculates the number and economic value of air pollution-related deaths and illnesses. The software incorporates a database that includes many of the concentration-response relationships, population files, and health and economic data needed to quantify these impacts (See U.S. EPA BenMAP 2022). Website: www.epa.gov/benmap

Both models estimate the dollar value of public health impacts using published economics literature that examines people's willingness to pay to reduce the risk of a particular health impact and documents the financial cost of the illness in terms of direct medical costs to a hospital and/or the opportunity costs related to an illness. They also rely on U.S. EPA's Value of a Statistical Life, which is based on people's willingness to pay for small reductions in mortality risks.

Option 2: Benefit per kWh Method for Electricity Air Emissions

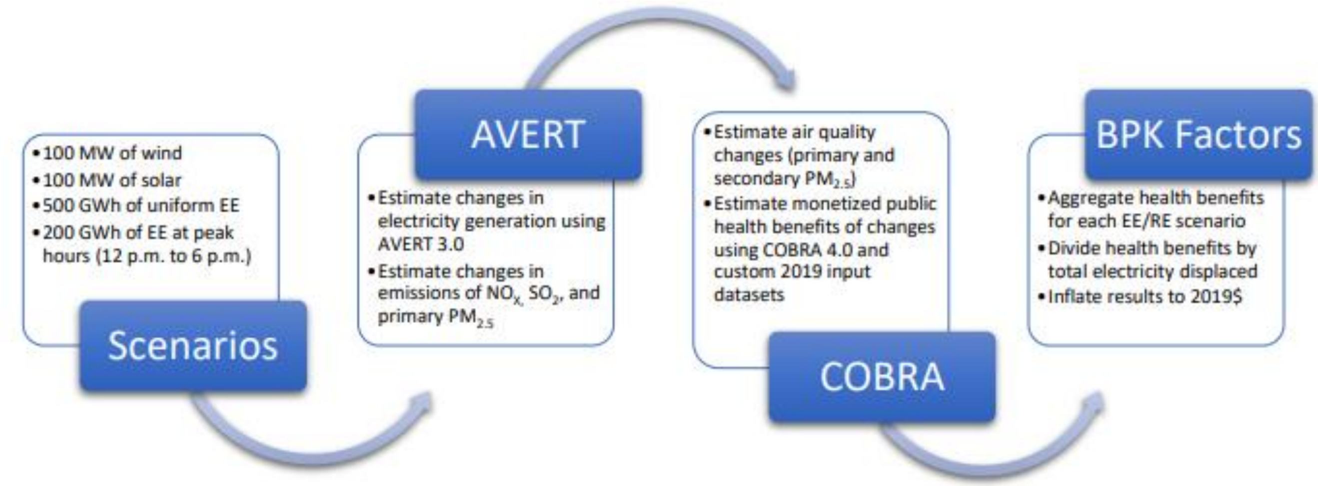
The U.S. EPA has developed values of the public health benefits associated with each kWh of electricity generation, referred to as benefit per kWh (BPK). These BPK values were prepared for electricity impacts using the steps described above for Option 1. Thus, this option is an alternative short-cut that can be used for electricity impacts instead of working through all the steps described above under Option 1. For public health impacts of gas or other fuels, this short-cut is not applicable, and the more comprehensive Option 1 will be necessary.

Applying this option requires only two simple steps. First, the energy impact of the DER (in kWh) should be established (see Step 1 above). Second, the dollar value of the health impact (in $) can be calculated by multiplying the energy impact (in kWh) by the BPK (in $/kWh).

The BPK values are provided for different regions of the country, and for certain states. These BPK values are also provided for different resource types, including energy efficiency, distributed solar, utility-scale solar, on-shore wind and off-shore wind, to reflect the different hourly load impact profiles of each resource (see U.S. EPA 2021; RAP 2021).

These BPK values are developed by the U.S. EPA using the AVERT and Cobra models described above. Figure 36 presents a summary of the steps and models used by the U.S. EPA to develop the BPK factors.

Figure 36. Overview of methods and models used in developing BPK factors



Source: U.S. EPA 2021, page 11.

This method is much simpler than using the general method described above, because the U.S. EPA has already performed many of the steps and applied the relevant models. The main disadvantage of this method is that it is limited to public health impacts of electricity generation. Estimates of public health impacts of other fuels, such as gas, oil, or gasoline, will require the general method described above.

7.2.3. Resources for Calculating Public Health Impacts

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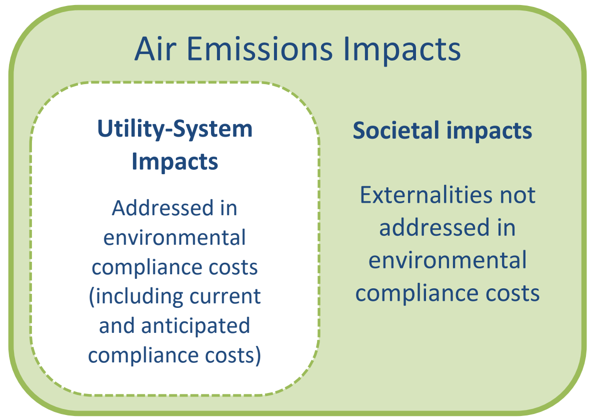
7.3. Other Environmental Impacts

7.3.1. Definition

Energy resources can have a variety of environmental impacts beyond air pollutant and GHG emissions. These include environmental impacts caused by land use for generation, transmission, and distribution of energy; water consumption; solid waste disposal; liquid waste disposal; fuel mining and transportation; disposal of technologies at the end of their useful life; and more.

Most DERs will reduce these types of environmental impacts by reducing electricity, gas, and other fuel consumption. As with GHG and air emissions, some DERs might increase other environmental impacts, and some might both increase and reduce environmental impacts.

Figure 37. Utility-system vs. societal air emissions impacts



It is important to distinguish between societal environmental impacts and environmental compliance impacts (see Figure 37 and Section 3.2.6.a). Societal environmental impacts represent the emissions that occur *after* compliance with environmental regulations and requirements. These societal impacts are referred to as "externalities" because they are external to the monetary prices of the goods that create them. The costs of compliance with environmental requirements, on the other hand, are considered "internal" costs because they are passed on to customers in electricity prices.

7.3.2. Methods for Calculating Other Environmental Impacts

Because of the breadth of other environmental impacts and the complexity of the methods for estimating them, describing all these methods is beyond the scope of this report. Readers looking for guidance on these impacts should refer to the relevant resources presented below.

7.3.3. Resources for Calculating Other Environmental Impacts

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7.4. Macroeconomic Impacts

Jurisdictions that have a policy goal of using energy investments to promote macroeconomic benefits should account for these impacts when assessing the cost-effectiveness of DERs, consistent with the guidance in the NSPM. Section 7.4.2 describes methods that can be used to estimate macroeconomic impacts for this purpose.

Avoiding double-counting macroeconomic impacts: Section 7.4.3 explains that the dollar values of macroeconomic impacts should not be simply added to the dollar values of the other impacts in the BCA, because there is too much overlap between macroeconomic impacts and utility system impacts. Instead, the macroeconomic impacts should be estimated and presented separately from the results of the BCA, to avoid double-counting of the overlapping impacts.

Note: This approach, presenting the macroeconomic results separately from the BCA results, is consistent with the approach of treating rate impacts separately from the BCA (see NSPM 2020, Appendix A) and with the approach of treating equity issues separately from the BCA results (see Chapter 9).

7.4.1. Definition

Investments in DERs will result in employment and other macroeconomic impacts. Table 71 shows the most frequently used indicators of macroeconomic development.

Table 71. Typical indicators of macroeconomic development

Job-years	A job-year is equivalent to a full-time employment opportunity for one person for one year (e.g., five job-years could be five jobs for one year or one job for five years).
Personal income	This refers to all income collectively received by all individuals or households. Personal income includes compensation from several sources including salaries, wages, and bonuses received from employment or self-employment.
State GDP	This is the total monetary or market value of all the finished goods and services produced within a state's borders.
State tax revenues	These come from property taxes, sales and gross receipts taxes, and individual income tax due to increased economic activity and employment within the state.

These different indicators of macroeconomic development are interrelated and overlap in several ways (see Synapse 2021 RI, page 13). Therefore, these indicators should not be added together.

Macroeconomic development impacts from energy resource investments include the three categories of impacts shown in Table 72 below.

Table 72. Three categories of macroeconomic development impacts from energy resource investments

Direct impacts	Jobs and economic activity associated with constructing, installing, and operating the energy resource.
Indirect impacts	Jobs and economic activity associated with additional work and revenue that such programs funnel to the supply chains associated with the direct impacts. These supply chains include contractors, builders/developers, equipment vendors, product retailers, distributors, manufacturers, and other elements.
Induced impacts	Jobs and economic activity created by the re-spending of the newly hired workers who gained employment in the direct or indirect impacts categories.

Investments in energy resource can have both positive and negative macroeconomic impacts. First, there is the positive impact caused by installing, operating, and maintaining the energy resource. Second, there may be a negative macroeconomic effect caused by avoiding or displacing other energy resources.

In addition, when customers experience a reduction in their utility bills, this money saved is assumed to be put back into the economy somehow, leading to additional macroeconomic development. This is referred to as the customer "respending" effect. When utility investments *reduce* utility bills on average, the customer respending effect leads to increased macroeconomic development. When utility investments *increase* utility bills on average, the customer respending effect leads to decreased macroeconomic development.

DERs create macroeconomic impacts in two different phases. The first phase is during the installation of the DER, which might last as long as a year or two. The second phase is during the operation of the DER, which lasts many years. In the second phase, most of the job and economic activity impacts are created from the reductions or increases in energy costs which lead to customer respending effects (see ACEEE 2019, page 2).

7.4.2. Methods for Calculating Macroeconomic Development Impacts

Table 73 describes approaches for estimating macroeconomic development impacts. For each method, macroeconomic development impacts are estimated by comparing the economic outcomes under the Reference Case to the economic outcomes associated with the DER Case. The difference between the two cases is the net macroeconomic impact attributable to the DERs.

Table 73. Macroeconomic development impacts: methods and models

Method	Description	Typical Use
Rules-of-thumb factors	Generic rules-of-thumb factors are simplified factors that represent relationships between key policy or program characteristics (e.g., financial spending, energy savings) and employment or output.	High-level screening analysis
Input-output models	Input-output models, also known as multiplier analysis models, can also be used to conduct analyses within a limited budget and timeframe, but provide more rigorous results than those derived from rules of thumb.	Short-term analysis of investments with limited scope and impact
Econometric models	Econometric models use mathematical and statistical techniques to analyze economic conditions both in the present and in the future to forecast how investments might affect income, employment, gross state product, and other common output metrics.	Short- and long-term analysis of investments with an economy-wide impact
Computable general equilibrium models (CGE)	CGE models use equations derived from economic theory to trace the flow of goods and services throughout an economy and solve for the levels of supply, demand, and prices across a specified set of markets.	Long-term analysis of Investments with an economy-wide impact
Hybrid models	Hybrid models typically combine aspects of CGE modeling with those of econometric models and may be based more heavily on one or the other.	Short- and long-term analysis of investments with a limited or economy-wide impact

Notes: Adapted from U.S. EPA 2018, Part 2, Chapter 5, Table 5-1. See this reference for a detailed discussion of the strengths and limitations of each approach.

Input-output modeling is one of the most frequently used methods to estimate macroeconomic development impacts given its relatively low cost and flexibility. Two common input-output models used to estimate the macroeconomic development impacts are:

- *REMI (Regional Economic Models Inc.) Model.* REMI is a proprietary dynamic forecasting and policy analysis tool. The model forecasts the future of a regional economy, and it predicts the effects on that same economy when the user implements a change. REMI models have been used throughout the world for a wide range of topic areas, including macroeconomic development, the environment, energy, transportation, and taxation, forecasting, and planning.
- *IMPLAN (Economic Impact Analysis for Planning, IMPLAN Group, LLC).* IMPLAN is a propriety, industry-standard input-output model that accounts for both the direct and indirect economic impact of an industry. IMPLAN was developed by the U.S. Forest Service in the 1970s to deliver accurate and timely estimates of economic impacts of forest resources.

These models are very comprehensive and address many aspects of the economy being modeled. Consequently, they require users to make assumptions and decisions in order to process the model outputs. For example, users often need to make assumptions about the flow of money within and outside of a state in order to determine in-state impacts.

It is important to set the appropriate boundary for the macroeconomic analysis. Macroeconomic development impacts from DERs can occur within a state, neighboring states, the entire United States, and even other countries. Most jurisdictions are interested in the macroeconomic development impacts within the state where the DER is implemented. In such cases, the in-state macroeconomic impacts should be isolated from the rest of the impacts.

Note that utility spending can lead to both an increase and a decrease in macroeconomic development. In the case of DERs, the increased development is the result of the purchase, installation, and maintenance of DERs, while the decreased macroeconomic development results from investments in generation, transmission, and distribution facilities that were avoided by the DERs. The macroeconomic impact of any energy resource should include the net macroeconomic effects, (i.e., both the increases and the decreases in macroeconomic development).

In sum, macroeconomic impacts should include increased macroeconomic development from increased utility and customer spending, plus reduced macroeconomic development from reduced utility spending, plus the customer respending effect.

Macroeconomic impacts should include increased macroeconomic development from increased utility and customer spending, plus reduced macroeconomic development from reduced utility spending, plus the customer respending effect.

Table 74 presents a summary of the methods for estimating macroeconomic impacts, including advantages and disadvantages of each method.

Table 74. Summary of methods for estimating macroeconomic impacts of energy resources

Tool	Description	Application	Advantages	Disadvantages
Adders and multipliers	A simple factor to scale up resource benefits to include or estimate economic development benefits from a given resource benefit amount	Once adder is determined or multiplier is estimated, can be applied to resource benefits estimates using simple arithmetic	Simplicity, transparency, ease of use, relatively low cost (adders more so than multipliers)	Limited accuracy, adders sometimes set somewhat arbitrarily
Input-output models	A relatively simple model that calculates benefits based on number of jobs required to sustain a given economic activity or the GDP created by economic activity	Practitioners must input the level of resources being invested and the savings they generate as well as the investment costs and other key parameters	Less expensive and easier to use than other types of models; transparent	Limited ability to assess impact of price changes; often do not assess changes over time
Econometric models	A more complicated model that relates changes in individual sectors and prices to one another and the economy as a whole	Typically require experienced modelers to program the investments and other key parameters	Thoroughly represent interactions between sectors and changes over time	Expensive; results heavily influenced by opaque parameters estimated by the modeler
CGE and hybrid models	A typically less-detailed model of the economy with relationships governed by economic theory and estimated parameters	Typically require experienced modelers to program investments and other key parameters	Theoretically consistent results; can project long-term impacts; available at state and local levels; hybrid models allow for unexploited investment opportunities	Expensive; results heavily influenced by opaque parameters and assumptions; unavailable at subnational levels; traditional CGE models assume a state of economic equilibrium

Source: Adapted from ACEEE 2019, page 8.

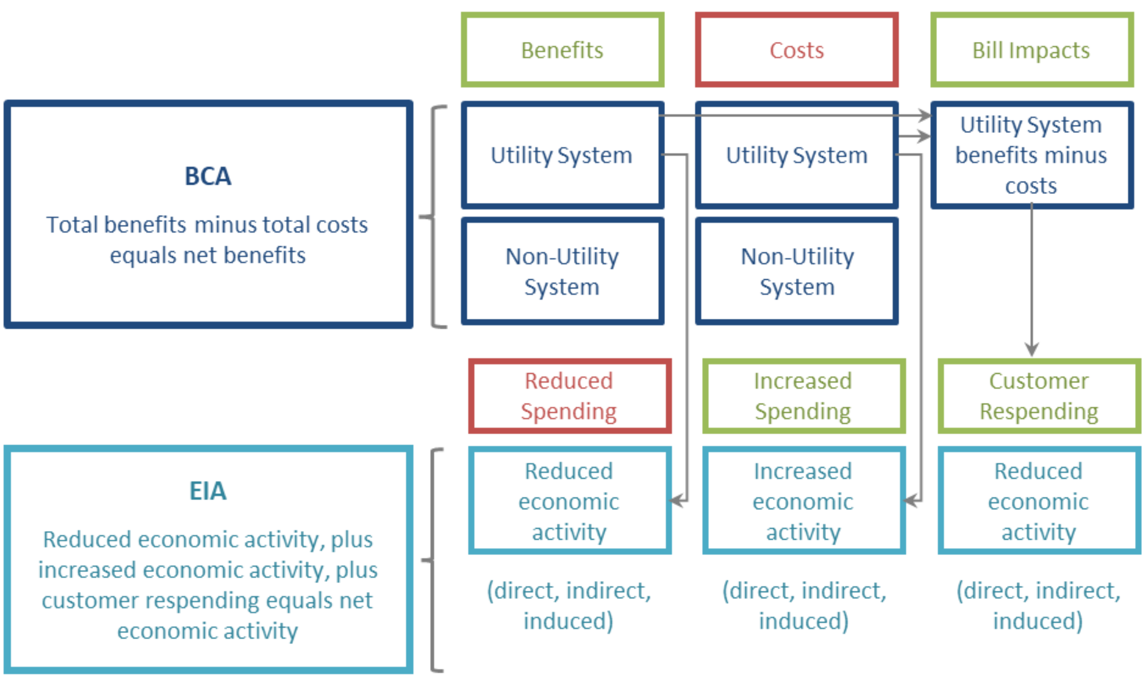
7.4.3. Role of Macroeconomic Development Impacts in a BCA

Consistent with NSPM guidance, monetary estimates of macroeconomic development impacts should not be added to the monetary cost-effectiveness analysis results, because they represent a different type of economic impact. The macroeconomic development benefits represent economic activity in the state, which is different from the customer and societal impacts included in an energy efficiency program BCA. Further, there are several aspects of BCAs and macroeconomic development analyses that overlap; therefore, adding the macroeconomic development results directly onto the BCA results will result in double-counting some of the effects (see NSPM 2020; Synapse 2019, Appendix B).

Figure 38 presents a comparison of the key elements of BCAs and macroeconomic development analyses. It indicates how some elements (e.g., benefits and costs) of a BCA may overlap with elements of the macroeconomic development analysis, resulting in significant overlap:

- The utility system benefits, in terms of avoided costs, result in reduced spending that leads to reduced economic activity.
- The utility system costs, in terms of resource investments, result in increased spending that leads to increased economic activity.
- The customer bill impacts, which are the difference between the utility system benefits and costs, result in customer respending effects that also lead to economic activity. Note that the customer bill impacts are not an additional cost or benefit in the BCA. Instead, they are an output of the BCA, equal to the utility system benefits minus the utility system costs. The bill impacts are separated out in the BCA portion of this graphic to make the point that those impacts are what lead to the customer respending effect in the macroeconomic impact analyses.

Figure 38. Comparison of benefit-cost analyses and macroeconomic impact analyses (EIA)



Source: Synapse 2021 RI.

Another way to describe the overlap between benefits and costs of DER BCAs and macroeconomic development analyses is that the cost of the goods and services purchased (or not purchased) as a result of the utility investment are included in the BCA, and they are also included in the macroeconomic development analyses in terms of the direct and indirect economic activity. There is not, however, a one-to-one relationship between the BCA impacts and the macroeconomic development impacts. In other words, a dollar spent on a utility investment in the BCA is not equivalent to a dollar of economic activity (GDP or otherwise) in the macroeconomic development analysis. This makes it very difficult, if not impossible, to separate the macroeconomic development impacts from the other BCA impacts.

Further, BCAs and macroeconomic development analyses serve two different purposes. BCAs are intended to indicate the costs and benefits to utilities, customers, and society (depending upon the perspective chosen), while macroeconomic development analyses are intended to show distributional impacts across different parties within society (see U.S. EPA, pages 11-2 through 11-9). Therefore, combining dollar values of one analysis with another would conflate the purposes and the findings of both of them.

While the macroeconomic development impacts should not be added directly to the dollar values in the BCA, they can nonetheless be accounted for in the decision-making process. This can be achieved by presenting the macroeconomic development impacts alongside the monetary results of the BCA (see U.S. EPA 2014, page 11-2). This approach allows utilities, stakeholders, and regulators the opportunity to review and understand the macroeconomic development impacts of the DER Case, and to use those impacts in informing the ultimate decision on whether the DERs are cost-effective.

While the macroeconomic development impacts should not be added directly to the dollar values in the BCA, they can nonetheless be accounted for in the decision-making process. This can be achieved by presenting the macroeconomic development impacts alongside the monetary results of the BCA.

The number of net job-years is the most useful metric to present alongside BCA results, because job growth is easily understood by a wide variety of stakeholders. The other indicators, such as net changes in GDP, personal income, and state tax revenues, can also be used as long as an explanation is provided about what each represents.

7.4.4. Resources for Calculating Macroeconomic Development Impacts

American Council for an Energy Efficient Economy. 2019. (ACEEE 2019). *State Policy Toolkit: Guidance on Measuring the Economic Development Benefits of Energy Efficiency*. www.aceee.org/sites/default/files/Jobs%20Toolkit%203-8-19.pdf.

Brattle Group. 2019. *Review of RI Test and Proposed Methodology*, prepared for National Grid.

Synapse Energy Economics. 2021. (Synapse 2021 RI). *Macroeconomic Impacts of the Rhode Island Community Remote Net Metering Program*. Prepared for the Rhode Island Division of Public Utilities and Carriers. March. www.ripuc.ri.gov/generalinfo/Synapse-CRNM-Macroeconomic-Report-2021.pdf.

U.S. Environmental Protection Agency. Updated 2014. (U.S. EPA 2014). *Guidelines for Preparing Economic Analyses.* National Center for Environmental Economics, Office of Policy. www.epa.gov/sites/default/files/2017-08/documents/ee-0568-50.pdf.

U.S. Environmental Protection Agency. 2018. (U.S. EPA 2018). *Quantifying the Multiple Benefits of Energy Efficiency and Renewable Energy: A Guide for State and Local Governments*.

www.epa.gov/statelocalenergy/quantifying-multiple-benefits-energy-efficiency-and-renewable-energy-guide-state.

7.5. Energy Security

Beyond the societal impacts discussed above, some jurisdictions may have policy goals supporting investment in DERs related to increasing energy security in the form of cybersecurity and/or energy independence. These impacts are described below; however, there is limited guidance on types of methods for quantifying these impacts. Further research on, and development of, methodological approaches is warranted to assist jurisdictions in being able to account for these impacts in assessing DER investments—the value of which is not zero, in particular with regard to cybersecurity given critical concerns in this area.

7.5.1. Definition

Cybersecurity is one aspect of energy security that DERs might affect. Many DERs are networked (i.e., connected to the internet or considered "smart" devices). Such DERs can include electric vehicles, electric vehicle charging stations, smart inverters, and devices with smart meters. These types of devices connected to the grid's distribution system potentially introduce cybersecurity vulnerabilities. Not only do potential cyberattacks and surveillance issues present a risk to the owner of the devices, but they also present a risk to the distribution grid.

As the prevalence of DERs increases, they may make distribution systems more vulnerable to cybersecurity attacks (see GAO 2021, NREL 2019). For example, attackers may be able to compromise a large number of high-wattage networked DERs (e.g., smart water heaters) and use them in a coordinated attack to disrupt grid operations. Best practices and standards for preventing DER-related cyberattacks are still being developed by North American Electric Reliability Corporation and National Institute of Standards and Technology (see NREL 2019).

Energy independence is another aspect of energy security that DERs might affect. DER investments that reduce energy imports from outside the jurisdiction, state, region, or country can help advance the goals of energy independence and security. The following quote describes the relationship between distributed resources and energy security:

> Energy independence can improve energy security, for example when using domestic energy efficiency and renewable energy resources to reduce dependence on foreign fuel sources. Avoiding the use of imported petroleum may yield political and economic benefits by protecting consumers from supply shortages and price shocks. Energy and national security are also improved when the existence of one easily targeted large unit with onsite fuel is replaced with many smaller units that are located in a variety of locations. (See U.S. EPA 2018, page 3-40.)

Several DERs—including electric vehicles, heat pumps, distributed solar PV, energy storage, and to some extent energy efficiency—reduce reliance on fossil fuels in the form of gasoline and diesel for internal combustion engine vehicles; natural gas, propane, or oil for home heating end-uses; and oil, coal, or natural gas for supplying electricity to the grid. Therefore, some DERs can improve energy security by reducing the amount of petroleum imported into the jurisdiction where the DER is located.

7.5.2. Methods for Accounting for Energy Security Impacts

7.5.2.a. Cybersecurity

Though costs from cyberattacks are well documented, few studies, if any, include the potential costs of cyberattacks in their cost-effectiveness tests for DERs.[20] This may be due to several factors, including:

- The low penetration of networked DERs to date;
- The uncertainty of the magnitude of potential DER-related cyberattacks; and
- The development of IEEE 1547.3 cybersecurity standards and protocols of networked DERs as their proliferation increases.

7.5.2.b. Energy Independence

Thus far, no studies known to the authors have attempted to estimate the value to energy independence from DER adoption. According to the U.S. EPA, energy security is a benefit of energy efficiency and renewable energy that has associated cost reductions, but the methodologies for quantifying them are purely qualitative or subject to debate (see U.S. EPA 2018).

7.5.3. Resources for Energy Security Impacts

Government Accountability Office. 2021. (GAO 2021). Electricity Grid Cybersecurity: DOE Needs to Ensure Its Plans Fully Address Risks to Distribution Systems. March. www.gao.gov/products/gao-21-81.

Institute of Electrical and Electronics Engineers Standards Association. 2020. (IEEE SA 2020). Guide for Cybersecurity of Distributed Energy Resources Interconnected with Electric Power Systems. www.standards.ieee.org/project/1547_3.html

National Renewable Energy Laboratory. 2019. (NREL 2019). *An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions*. April. www.nrel.gov/docs/fy19osti/72102.pdf.

Radware. 2019. *2018-2019 Global Application & Network Security Report*. www.radware.com/ert-report-2018/.

U.S. Environmental Protection Agency. 2018. (U.S. EPA 2018). *Quantifying the Multiple Benefits of Energy Efficiency and Renewable Energy: A Guide for State and Local Governments*. www.epa.gov/statelocalenergy/quantifying-multiple-benefits-energy-efficiency-and-renewable-energy-guide-state.

[20] According to Radware, the cost of a cyberattack in 2018 and 2019 was about $1.1 million (see Radware 2019).

8. Reliability and Resilience

Reliability and resilience impacts can affect the utility system, host customers, and society. This chapter addresses each perspective separately.

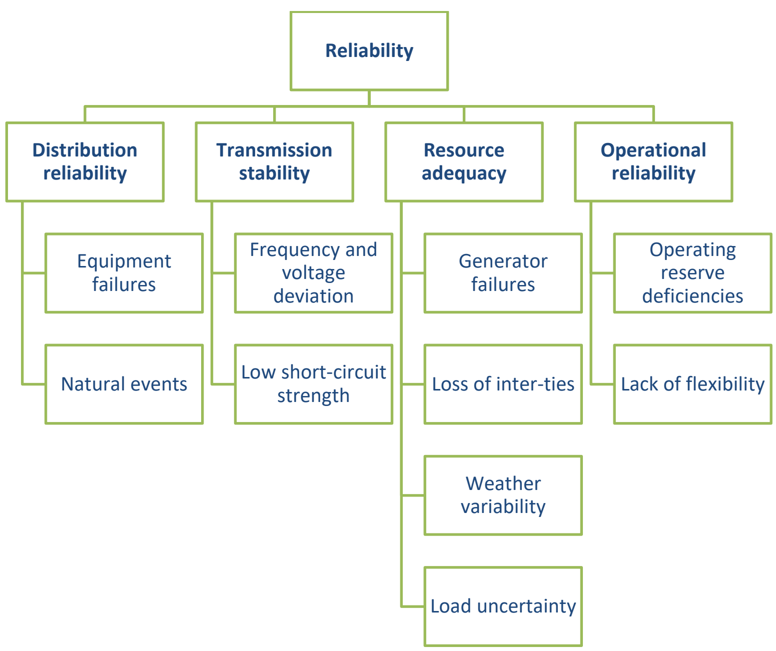
8.1. Reliability

8.1.1. Definition

The U.S. Department of Energy defines reliability as the ability of the system or its components to prevent or withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components (see DOE 2017, page 4-1). Reliability is distinct from resilience in that the latter is focused more on addressing severe weather events and major equipment failures, reducing long-duration outages, and reducing outages for critical needs customers and end-uses (see Section 8.2.1).

Figure 39 indicates how there are many different aspects to reliability. These include transmission, distribution, and generation (adequacy and operational) aspects. Most electricity outages are caused by distribution system failures or interruptions. Transmission system failures or interruptions are the second greatest cause of major electricity outages. Generator availability and operation are rarely the cause of major electricity outages.

Figure 39. Different aspects of reliability



Source: Adapted from LBNL 2021 R&R of EE, page 4, Figure 2.

Utilities are typically subject to minimum reliability performance standards for both the bulk power system and the local distribution system. These performance standards are often monitored and enforced using metrics and financial incentives related to the frequency, duration, and extent of power outages experienced by customers. Commonly used metrics include the system average interruption duration index (SAIDI), the system average interruption frequency index (SAIFI), and the customer average interruption duration index (CAIDI).

Further, in order to maintain a reliable source of electric or gas capacity, vertically integrated utilities use planning reserve margins that are designed to provide enough extra generation or production capacity beyond forecasted peak demand to minimize outages and outage times. These reserve margins are designed to be large enough to meet certain reliability criteria, such as ensuring that the loss of load probability (LOLP) does not exceed one day in ten years.

By lowering loads or increasing generation on the grid, DERs can reduce the probability and/or duration of customer service interruptions (see U.S. EPA 2018, page 3-35). The magnitude of the value of this benefit will vary, with less value to systems that have excess capacity or newly installed capacity, and greater value to systems that are short of capacity or have a large amount of aging infrastructure.

To the extent that DERs reduce capacity requirements at the bulk system level, they also reduce associated reliability requirements. Consequently, ancillary service, generating capacity, and transmission capacity values *implicitly* include the value of reliability for a set standard. In other words, the $/MW value of a DER's avoided ancillary services requirements, avoided generating capacity, and avoided transmission capacity include that DER's contribution to meeting reliability requirements. Therefore, calculations of reliability benefits for DERs should include only the incremental reliability benefits beyond those captured in the avoided costs for ancillary services, generation capacity, and transmission capacity.

Planning reserve margins and other reliability requirements are often influenced by the size and the diversity of the resources on the system. For example, a system made up of a few large central generators will require a higher reserve margin than one made up of many decentralized generators and DERs. This creates an inherent reliability advantage of DERs.

Most reliability benefits accrue to the utility system. Some reliability benefits, however, might accrue to the host customer or customers. An example of this would be when a micro-grid or a combination of distributed generation and distributed storage allows the host or hosts to continue to have power during a power outage. Other reliability benefits might accrue to society—for instance when a micro-grid or a combination of distributed generation and distributed storage allows critical customers such as a police stations, fire stations, or hospitals to continue to provide public services during a power outage. In those instances where the distinction between utility system, host customer, and societal impacts matters, the reliability benefits should be calculated separately for these three different perspectives.

Since reliability and resilience impacts are so similar and potentially overlapping, it is important that any estimate of DER reliability and resilience benefits avoid double-counting.

Since reliability and resilience impacts are so similar and potentially overlapping, it is important that any estimate of DER reliability and resilience benefits avoid double-counting.

8.1.2. Methods for Calculating Reliability Impacts

Reliability Assessment Framework	States Preferences (Bottom Up)	Revealed Preferences (Bottom Up)	Quantitative Models (Bottom Up)	Macroeconomic Methods
• Define reliability metrics • Define and quantify baseline reliability • Characterize the potential reliability impacts of DERs • Quantify the reliability impacts from the proposed DERs • Calculate the net reliability impacts of the proposed DERs • Calculate the dollar values of the reliability impacts	• Use customer surveys such as customer interruption cost surveys • Gather information on the costs resulting from shorter duration, localized power interruptions borne by customers	• Use actual customer purchasing behavior to infer a valuation of non-market goods • Use defensive behavior methods identify the amount that customers have paid to avoid the negative consequences of a power interruption • Use damage cost methods calculate the actual costs that may be experienced by customers during a power interruption	• Use tool such as LBNL's ICE model to value reliability and resilience impacts for short (<8 hours) outage durations • OR use distribution system using load flow analysis to model improvements in reliability if detailed circuit-specific data is available	• Use indicators such as economic output and employment to analyze effects of power outages on regional economies to capture societal macroeconomic aspect • Use methods that analyze economic output and job impacts of changes to the electricity or gas industries

Framework for Assessing Reliability

Reliability impacts can be estimated by comparing the reliability metrics from a baseline scenario with those from a scenario that includes the proposed DERs, using the steps in Table 75.

Table 75. Reliability assessment framework steps overview

Step 1	**Define reliability metrics** This requires identifying metrics that can be used to define, assess, and prioritize reliability impacts (see LBNL 2021 R&R for EE). There are many such metrics available for this purpose. Table 76 presents some examples of commonly used metrics. For the purpose of assessing reliability in a BCA, it may be useful and practical to focus on a subset of relevant metrics that address key areas of reliability, such as LOLP, Planning Reserve Margin, SAIDI, and SAIFI. Table 76 below provides examples of metrics.
Step 2	**Define and quantify baseline reliability** This is equivalent to developing a Reference Case, where the relevant reliability metrics (from Step 1) are quantified and presented to indicate the level of reliability that would be expected without the DERs being evaluated in the BCA. It is especially important to determine the values for the monetary metrics, because these will be used to determine the dollar value of reliability.
Step 3	**Characterize the potential reliability impacts of DERs** This critical step includes an assessment of the potential for the proposed DERs to affect the relevant reliability metrics (from Step 1). This requires a thorough analysis of the DER types and load impact profiles. Some DER types, such as energy efficiency and distributed PV, might passively affect reliability by simply reducing load during peak hours or by enhancing system diversity and adding multiple modular, decentralized resources. Other DER types, such as demand response and distributed storage, might actively affect reliability by operating at times when additional reliability is needed. Still other types of DERs, including micro-grids or combinations of distributed PV and storage, can continue to provide electricity service to host customers during an outage. These different types of reliability impacts should be identified for each DER type.

Step 4	**Quantify the reliability impacts from the proposed DERs** This is equivalent to developing a DER Case, where the relevant reliability metrics (from Step 1) are quantified and presented to indicate the level of reliability that would be expected as a result of installing those DERs. Again, it is especially important to determine the values of the monetary metrics.
Step 5	**Calculate the net reliability impacts of the proposed DERs** This requires subtracting the reliability impacts from the DER Case (from Step 4) from the reliability impacts of the Reference Case (from Step 2).
Step 6	**Calculate the dollar values of the reliability impacts** This requires applying a dollar value to the relevant reliability metrics. For example, the system LOLE (in hours per year) can be multiplied by the value of lost load, or VOLL, (in dollars per hour) to calculate the value of the change in reliability (in dollars per year). Methods for determining the dollar value of reliability are discussed below. (See LBNL 2021 R&R of EE, page 16 for a discussion of the challenges of using VOLL in BCAs.)

In some cases, an additional step may be warranted. In those instances where the distinction between utility system, host customer, and societal impacts matters, the reliability benefits should be calculated separately for these three different perspectives.

Table 76. Examples of reliability metrics

Distribution System	System Average Interruption Duration Index (SAIDI)
	System Average Interruption Frequency Index (SAIFI)
	Customer Average Interruption Duration Index (CAIDI)
	Momentary Average Interruption Frequency Index (MAIFI)
	Customers Experiencing Multiple Interruptions (CEMI)
	Customers Experiencing Longest Interruption Duration (CELID)
Transmission System	N-1 analysis
	Loss-of-Load Probability (LOLP) in terms of days per ten years
	Loss-of-Load Expectation (LOLE) in terms of hours per year
Generation System	Planning Reserve Margin
	Effective Load Carrying Capacity (ELCC)
	LOLP and LOLE
Monetary	Value of Lost Load (VOLL)
	Customer Interruption Costs (CIC)
	Service Restoration Costs

Methods for Determining Dollar Values of Reliability

Multiple methods are used to calculate the dollar values of reliability. Some of the most common methods are summarized below.

Bottom-Up Methods

Stated Preferences

Surveys are a common approach to identify stated preferences for a variety of different economic and societal impacts. Customer interruption cost surveys are the most common method determining dollar values for reliability because they can estimate direct costs for a variety of power interruption scenarios. These scenarios can range from previous interruptions experienced by customers to different, but closely related, hypothetical interruptions (see NARUC 2019, page 17).

Customer interruption cost surveys are particularly well-suited for gathering information on the costs that result from shorter duration, localized power interruptions because respondents have experienced these types of interruptions in the past and because the costs consist largely of the direct costs that are borne solely by the respondents (see LBNL 2021 Resilience, pages 17-19).

Revealed Preferences

The revealed preferences approach is used in many applications to develop a dollar value for costs or benefits that are not typically priced in an economic transaction. It uses actual customer purchasing behavior to infer a valuation of non-market goods. Defensive behavior and damage cost methods are examples of revealed preference approaches that have been used to establish the value of avoiding power interruptions.

- Defensive behavior methods identify the amount that customers have paid to avoid the negative consequences of a power interruption (see NARUC 2019, page 17). For example, the costs of purchasing and maintaining a back-up diesel generator or a micro-grid could represent the value of avoiding power interruptions.
- Damage cost methods calculate the actual costs that may be experienced by customers during a power interruption (see NARUC 2019, page 17). As one example, customer VOLL can be determined by calculating the value of leisure time for individuals and calculating the proportion of that leisure value that is dependent on electricity. The value of leisure can then be estimated using the assumption that, at the margin, an hour of leisure is valued the same as the income generated from an additional hour of work, which is valued at a relevant labor rate (see CEPA 2018).

Quantitative Models

Many states and utilities use the Lawrence Berkeley National Laboratory's Interruption Cost Estimate (ICE) Calculator to value reliability and resilience impacts. The ICE Calculator is a web-based tool that estimates outage impacts on consumers while considering the probability of the outage's occurrence. This tool is designed for electric reliability planners at utilities, government organizations, and other entities that are interested in estimating interruption costs and/or the benefits associated with reliability and resilience improvements in the United States. This tool relies in part on customer surveys (i.e., stated preferences) to estimate the monetary VOLL associated with power outages for different customer and outate types (see LBNL ICE).

The ICE model has several limitations, however. The data is focused on relatively short outages (less than 24 hours) and is not intended to be used for outage durations exceeding eight hours, making the model less useful for resilience purposes. In addition, for large commercial and industrial (C&I) customers, the VOLL is based on GDP/kWh by state, while for small C&I customers and residential customers, it uses survey data from surveys conducted by 10 utilities in certain parts of the country. No surveys were performed for some regions or states, and much of the survey data is outdated (ranging from 1989 to 2012). LBNL is working on addressing some of these limitations (see LBNL 2021 Eto).

Depending on data availability, it might also be possible to model improvements in reliability (above minimum operating standards) from DERs on the distribution system using load flow analysis. Detailed circuit-specific data would be required to conduct such analysis, including the number of customers by class, the current level of reliability, and future capacity needs.

Methods for Calculating Macroeconomic Impacts

Economy-wide methods analyze the effects of power outages on regional economies using indicators such as economic output and employment (see NARUC 2019, page 18; LBNL 2021 Resilience, pages 19-25). These approaches do not necessarily capture the full impact of outages on customers. Instead, they capture one aspect of outages: the societal macroeconomic aspect.

A variety of methods and models are available to analyze economic output and job impacts of changes to the electricity or gas industries. These include rules-of-thumb factors; input-output models (e.g., IMPLAN and REMI); econometric models; general equilibrium models; and hybrid models (see Section 7.4.2).

Tools for Calculating Reliability Impacts

Several tools have been established to facilitate the calculation of reliability impacts. Table 77 presents a summary of these tools. Additional discussion of strengths, limitations, and uses of these tools is provided in NARUC & NASEO 2022.

Table 77. Current and pending tools for calculating reliability impacts

Method/Tool	Developers	Advantages and New Additions	Available
Interruption Cost Estimator 2.0 Tool	• Lawrence Berkeley National Laboratory • Edison Electric Institute	• Updated calculations of power interruption costs. • New willingness-to-pay surveys that will populate the tool with more recent data and more geographic specificity for power interruption cost estimates. • New data on customer responses to longer-duration power interruptions.	Expected 2023
Customer Damage Function Calculator Tool	• National Renewable Energy Laboratory	• Helps individual facilities (or groups of similar facilities) calculate power interruption costs, based on the specific losses that they project will occur. • Guided questions lead facilities through their own assessments. • Graphical summary of initial damage costs, and costs over time.	2021
Social Burden Method	• Sandia National Laboratories • University of Buffalo	• Provides a metric for the social burden of power outages that emphasizes the needs of communities during power outages, instead of emphasizing protecting critical infrastructure for its own sake. • Adopts a more neutral treatment of the willingness to pay vs. the ability to pay for resilience.	Pilot 2021-2022
FEMA Benefit-Cost Analysis Tool	• Federal Emergency Management Agency	• Provides quantitative values for lost emergency services, such as police, fire, and emergency medical response.	2021

Method/Tool	Developers	Advantages and New Additions	Available
		• New pre-calculated values specifically for hospitals published in 2021. • The use of FEMA values aligns with the application requirements of FEMA grant programs.	
Power Outage Economics Tool (POET)	• Lawrence Berkeley National Laboratory • ComEd	• Estimates the economic impacts of longer-duration power outages. • Takes into account how utility customers adapt their behavior during longer duration power interruptions. • Uses surveys of utility customers to collect data on how they would actually behave during a power outage.	Pilot 2021-2022

Source: Recreated from NARUC & NASEO 2022, Table 2, page 13.

8.1.3. Resources for Calculating Reliability Impacts

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8.2. Resilience

8.2.1. Definition

Resilience is increasingly recognized as an important consideration separate from and in addition to reliability. DERs can have important impacts on the resilience of an electric or gas system. Several definitions of resilience have been used in recent years, including:

- "Robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event" (see NARUC 2013, page 1).
- "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the ability to anticipate, absorb, adapt to, and/or rapidly recover from such an event" (see FERC 2018, page 13; IEEE 2021, page 8).
- "The ability of a power system and its components to withstand and adapt to disruptions and rapidly recover from them" (see U.S. DOE 2013).
- "The ability of the system and its components (i.e., both the equipment and human components) to minimize the damage and improve recovery from the non-routine disruptions, including high impact, low frequency events, in a reasonable amount of time" (see NATF 2021, page 1).

Consistent across these definitions is the notion that major events will occur, but more resilient systems will minimize the effects of these events—by both reducing the likelihood or scope of an outage and by reducing the duration of outages that do occur.

Resilience vs. Reliability: Resilience differs from reliability in that it addresses *severe outage* events and *long-duration* outages. Resilience also differs from reliability in that it is more focused on critical need customers and loads. Critical need customers include customers who rely upon electricity and gas services more than average customers; for example, police stations, fire stations, hospitals, other health care centers, water and wastewater processing facilities, military installations, customers relying upon life support systems, community emergency shelters, communications systems, and more.

Since reliability and resilience impacts are so similar and potentially overlapping, it is important that any estimate of resilience benefits from DERs avoid double counting the reliability benefits associated with those DERs.

Not all DERs have resilience impacts. When determining the potential magnitude of DER resilience impacts, it is useful to start with a set of traits that DERs might have that enable them to provide resilience benefits (see NARUC 2020, page 4):

- Dispatchability, when DERs can respond to a disruption at any time with little to no advanced warning.
- Islanding capability, when DERs have the capability to isolate specific loads, a customer, or customers from the rest of the distribution grid and continue to serve those customers during the outage.
- Siting at critical customer locations, when DERs are located at critical loads (e.g., police stations) or at critical points in the grid (e.g., residential apartment buildings).
- Fuel security, when DERs do not rely upon the availability or deliverability of a limited physical fuel to operate.
- Quick ramping, when DERs are capable of changing output quickly to respond to rapidly changing load.
- Grid services, when DERs can provide voltage support, frequency response, and other grid services.
- Decentralization, when DERs are sized and sited to support distributed load.
- Flexibility, when DERs can be deployed and operated quickly (relative to other supply-side resources) at locations and times where resources are needed.

Microgrids are frequently attributed with resilience benefits because they have most or all these traits (see NARUC & NASEO 2022). Similarly, distributed solar resources paired with distributed storage are generally recognized as offering resilience benefits. Energy efficiency is sometimes attributed the following resilience benefits: (a) it reduces demand, which allows customers to install smaller backup or emergency power sources at lower cost; (b) lower customer demand can allow generation resources to restart more easily after power blackouts; and (c) efficient building shells and appliances can allow customers to live safely in their homes longer during extended outages (see ACEEE 2020 Three Rs, page 21).

8.2.2. Methods for Calculating Resilience Impacts

Framework for Assessing Resilience Impacts

Few jurisdictions, if any, have determined values for resilience for the purpose of BCAs (See ACEEE 2020 Three Rs; NARUC 2019). However, some studies have offered frameworks for how resilience impacts could be calculated (See NARUC & NASEO 2022; IPI 2018, pages 16-19).

Resilience impacts can be estimated by comparing the resilience metrics from a baseline scenario with those from a scenario that includes the proposed DERs, using the steps shown in Table 78.

Table 78. Steps to assess resilience impacts

Step 1	**Characterize the threats** These might include extreme weather events, earthquakes, wildfires, cyberattacks, and more (see U.S. DOE 2017, pages 4-26 to 4-27). The threats might vary in type and magnitude across states. Ideally, probabilities for the different threats would be developed in order to prioritize them, weight them, and apply risk assessment techniques to them (see Chapter 6).
Step 2	**Define resilience metrics** This requires identifying metrics that can be used to define, assess, and prioritize resilience impacts. There are many such metrics available for this purpose (see Table 79). For the purpose of assessing resilience in a BCA, it may be useful and practical to focus on a subset of relevant of metrics that address key areas of resilience, such as critical customer-hours of outages, time to recovery, and critical services without power. Depending upon the DER type and the goal of the BCA, it might be useful to apply these metrics to different perspectives and customer types. For example, these metrics could be characterized and reported according to whether they apply to the utility system, the host customer, or society. In addition, some of these metrics could be further characterized according to critical versus non-critical customers.
Step 3	**Define and quantify baseline resilience** This is equivalent to developing a Reference Case, where the relevant resilience metrics (from Step 2) are quantified and presented to indicate the level of resilience that would be expected without the DERs being evaluated in the BCA.
Step 4	**Characterize potential resilience impacts of DERs** This critical step includes an assessment of the potential for the proposed DERs to affect the resilience metrics (from Step 2). This requires a thorough analysis of the DER type and load impact profile, including the extent to which the proposed DER has the resilience traits outlined above in Section 8.2.1. Some DER types, such as energy efficiency and distributed PV, might passively affect resilience by simply reducing load during peak hours. Other DER types, such as demand response and distributed storage, might actively affect resilience by operating at times when additional power is needed. Still other types of DERs, including micro-grids or combinations of distributed PV and storage, can continue to provide electricity service to host customers during an outage. These different types of resilience impacts should be identified for each DER type.
Step 5	**Quantify resilience impacts from proposed DERs** This is equivalent to developing a DER Case, where the resilience metrics (from Step 2) are quantified and presented to indicate the level of resilience that would be expected as a result of installing those DERs.
Step 6	**Calculate net resilience impacts of proposed DERs** This requires subtracting the resilience impacts from the DER Case (from Step 5) from the resilience impacts of the Reference case (from Step 3).

Step 7 Calculate dollar values of resilience impacts

This requires applying a dollar value to the relevant resilience metrics. For example, the critical customer-hours of outage (in hours per year) can be multiplied by the loss of assets or the business interruption costs (in dollars per hour) to calculate the value of the change in resilience (in dollars per year). Methods for determining the dollar value of resilience are discussed below.

In some cases, an additional step may be warranted. Some resilience benefits might accrue to the utility system. Some resilience benefits might accrue to the host customer or customers, e.g., when a micro-grid or a combination of distributed generation and distributed storage allows the host or hosts to continue to have power during a power outage. Other resilience benefits might accrue to society, e.g., when a micro-grid or a combination of distributed generation and distributed storage allows a critical customer, such as a police station, fire station, or hospital, to continue to provide public services during a power outage. In those instances where the distinction between utility system, host customer, and societal impacts matters, the resilience benefits should be calculated separately for these three different perspectives.

Table 79 presents a list of resilience metrics established by the U.S. DOE. Several other sources also offer resilience metrics (see Sandia 2020 Metrics, pages 18-28; IEEE 2021, pages 12 and 13).

Table 79. DOE resilience metrics

IMPACT	Consequence Category	Resilience Metrics
Direct	Electric Service	Cumulative customer-hours of outages
		Cumulative customer energy demand not served
		Average number (or %) of customers experiencing an outage during a specified time
	Critical Electrical Service	Cumulative critical customer-hours of outages
		Critical customer energy demand not served
		Average number (or %) of critical loads that experience an outage
	Restoration	Time to recovery
		Cost of recovery
	Monetary	Loss of utility revenue
		Cost of grid damages (e.g., repair or replace lines, transformers)
		Cost of recovery
		Avoided outage cost
Indirect	Community Function	Critical services without power (e.g., hospitals, fire stations, police stations)
	Monetary	Loss of assets and perishables
		Business interruption costs
		Impact on the gross municipal product or gross regional product
	Other Critical Assets	Key production facilities without power
		Key military facilities without power

Source: Recreated from IEEE 2021, page 14. For a discussion of the challenges of using VOLL in BCAs, see LBNL 2021 R&R of EE, pages 16-17.

Methods for Determining Dollar Values of Resilience

The monetary metrics for resilience can be calculated using many of the same methods and tools that are used to determine dollar values of reliability (see Section 8.1.2) In some cases, these methods might need to be tailored to better reflect the impacts of resilience. For example, customer interruption cost surveys are frequently used for determining dollar values for reliability. In the case of resilience, it will be important to survey a robust sample of critical customers. In fact, the value of reliability might even differ considerably between different types of critical customers, (for instance, between a residential customer on life-support and a wastewater processing facility).

Further, customer interruption cost surveys might be less suitable for estimating the impacts of widespread long-duration power interruptions because respondents might have no past experiences to draw upon in estimating the costs they might bear. Thus, without substantial help, respondents might not be able to fully consider the various implications of hypothetical widespread long-duration power interruptions and might have difficulty estimating their costs. Moreover, individual customers are unlikely to have knowledge of the indirect costs borne by other customers, such as the cascading economic impacts of power interruptions throughout supply chains (see LBNL 2021 Resilience, pages 17-19.)

Tools for Calculating Resilience Impacts

Several tools have been established to facilitate the development of resilience impacts. These tools are summarized in Table 77 above. Additional discussion of strengths, limitations, and uses of these tools is provided in NARUC & NASEO 2022.

8.2.3. Resources for Calculating Resilience Impacts

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9. Energy Equity

9.1. Overview

Energy equity has several different dimensions, and BCAs can address only some of them. This chapter describes the limitations of BCAs in informing energy equity decisions and provides a conceptual framework for how to combine BCAs with distributional equity analyses (DEAs) to fully assess equity in DER investment decisions.

Energy equity is a complex and evolving topic. More detailed guidance on these issues is beyond the scope of this MTR handbook and warrants further consideration and development.

9.2. Definitions

9.2.1. Energy Equity

There is no standard definition of "energy equity" in the electric and gas utility industries. Some organizations define "energy equity" and "energy justice" as the same thing. Others view them as separate, with energy justice encompassing, among other things, the remediation of historical injustices in the energy system. For the purposes of this chapter, the following definition from the Pacific Northwest National Laboratory is helpful:

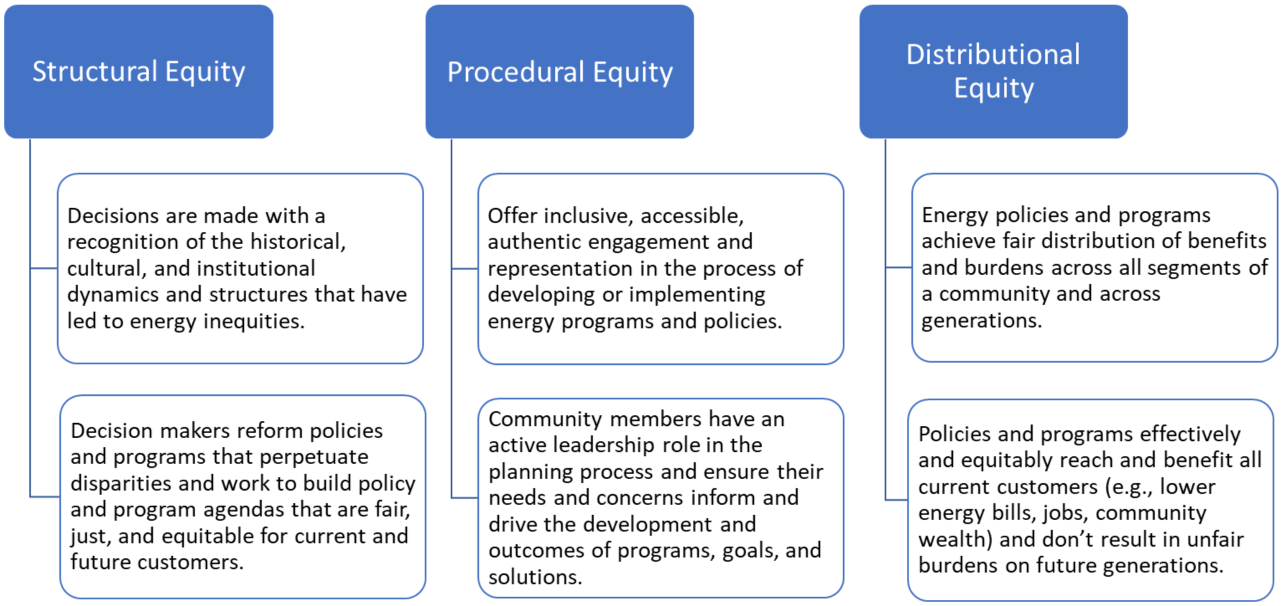
> An equitable energy system is one where the economic, health, and social benefits of participation extend to all levels of society, regardless of ability, race, or socioeconomic status. Achieving energy equity requires intentionally designing systems, technology, procedures, and policies that lead to the fair and just distribution of benefits in the energy system (see PNNL Energy Equity).

9.2.2. Dimensions of Equity

Energy equity has three different inter-related dimensions—structural, procedural, and distributional—as shown in Figure 40. Ensuring equitable DER programs and policies will require careful consideration of all three dimensions of equity. Many jurisdictions have identified a broad range of structural and procedural metrics to help achieve their energy equity goals (LBNL 2021 Equity). Some have also identified certain distributional metrics, such as reducing energy burden and increasing participation in utility and other publicly funded energy programs. BCAs, however, are not designed to address procedural or structural equity. And the extent to which BCAs currently address distributional equity is fairly limited, as described below.[21]

[21] There are some ways in which procedural and structural equity might overlap with BCAs. For example, procedural equity requires that target populations are able to provide meaningful input to BCAs.

Figure 40. Dimensions of Energy Equity



Source: Adapted from the American Council for an Energy Efficient Economy (see ACEEE Energy Equity).

The equity dimensions above largely address *intra*-generational impacts (e.g., ensuring all *current* customers benefit from DER investments). However, one component of distributional equity is *inter*generational equity[22] which generally refers to meeting the needs of current customers without compromising the ability of meeting the needs of future customers. Intergenerational equity is discussed further in Section 9.3.4.

9.2.3. Target Populations

Jurisdictions are increasingly identifying specific populations to ensure that there is an equitable allocation of costs and benefits in energy investment decisions across all customers. These specific populations can include environmental justice communities, disadvantaged communities, low-income households, marginalized communities, limited English-proficiency households, and the businesses and organizations that serve these communities. For the purposes of this report, these people and communities that are the subject of energy equity concerns are referred to collectively as "target populations."

Table 80 provides several examples of target populations used by jurisdictions for equity purposes. It illustrates the variation in how these populations have been identified to date.

[22] Intergenerational equity can be referred to as "transgenerational" equity. Some equity frameworks consider transgenerational equity as a separate dimension of equity alongside structural, procedural, and distributional equity (see ACEEE Energy Equity). For the purposes of this framework, however, intergenerational equity is encompassed within each dimension, in particular structural and distributional equity, as described in Figure 40.

Table 80. Target population examples used by some jurisdictions

Targeted Population	Definition
Underserved Populations	People who have limited or a decreased level of service or access to energy system services
Marginalized Populations	People excluded from participating in decision-making and those who lack access to basic economic, political, cultural, and social activities
Vulnerable Populations	Those who are economically disadvantaged, racial and ethnic minorities, the elderly, rural residents, linguistically isolated, those with inadequate education, and those with other socioeconomic challenges
Highly Impacted Populations	Communities living in geographic locations characterized by energy inequity and facing economic or historical barriers to participation in energy decisions and solutions
Disadvantaged Populations	Those who most suffer from economic, health, and environmental burdens
Over-Burdened Populations	Minority, low-income, tribal or indigenous populations, or geographic locations that potentially experience disproportionate environmental harms and risks
Fenceline Populations	Communities living in closest proximity to dangerous facilities (within one-tenth of a facility's vulnerability zone), also referred to as "frontline" populations
Low- to Moderate-Income People	People who make less than a certain income threshold relative to the area median income

Source: Adapted from PNNL Energy Equity.

This chapter does not provide guidance on how a jurisdiction should define their target population, as such definitions and categories can vary from state to state Instead, this chapter focuses on key considerations in accounting for the distribution of DER costs and benefits that accrue to target populations compared to general customers.

9.3. Methods for Assessing Energy Equity

9.3.1. Benefit-Cost Analysis

Regulators, utilities, and others have traditionally tried to address some aspects of energy equity by providing energy efficiency programs to low-income customers, and by accounting for the specific costs and benefits of those programs in a BCA. Sometimes these costs and benefits are accounted for in the low-income host customer impacts, and in other cases they are accounted for by applying alternative benefit-cost ratio thresholds for low-income programs (see Chapter 6 for methods on quantifying host customer impacts). Further, some jurisdictions account for societal impacts of DER investments that recognize certain benefits that are important to achieving equity goals, e.g., reduced air emissions, improved public health, job creation, etc. (see Chapter 6 for methods on quantifying societal impacts).

However, accounting for low-income and societal impacts in a BCA *does not provide information on how the costs and benefits of DERs are distributed between target populations and other customers*. This is the key aspect of customer equity that BCAs are not typically designed to address to date.

BCAs compare an investment's benefits to its costs, "without any consideration of who pays the costs nor who receives the benefits.

BCAs are not designed to assess *distributional* impacts between customers, i.e., the impacts that vary between different categories of customers. BCAs compare an investment's benefits to its costs, "without any consideration of who pays the costs nor who receives the benefits" (NYU IPI, page 5). Instead, they are intended to address impacts on customers or society on average, i.e., in absolute terms as opposed to relative terms. Yet achieving equity requires consideration of the *distributional impacts between* customers. Achieving equity, by definition, requires comparing impacts on some groups of customers relative to other groups.

Many of the benefits of DERs, in terms of avoided costs, are shared across all customers. Similarly, the utility system costs of DER programs are typically passed on to all customers.[23] Thus, the costs and benefits included in a BCA are typically a blend of impacts experienced by all customers, by society, by broad customer categories, or by host customers. Therefore, the bottom-line results of the BCA, in terms of net benefits or a benefit-cost ratio, cannot be broken out to indicate distributional effects across customers or on target populations.

This limitation is true even for a DER program that is specifically designed to serve a target population. For example, a BCA test for a low- to moderate-income (LMI) energy efficiency program that includes the LMI host customer non-energy benefits also includes the avoided cost benefits that are experienced by all customer sectors. And the avoided costs used in most BCAs are the utility system avoided costs, not the LMI host customer bill savings. Further, the costs of LMI energy efficiency programs are typically passed on to all other customers, and many LMI energy efficiency programs do not require the host customers themselves to pay any portion of the energy efficiency measure costs. Thus, a BCA for an LMI energy efficiency program (or any program for a target population) includes a blend of costs and benefits experienced by the host customers and other customers, and it is not possible to break out any distributional effects of those programs.

The costs and benefits included in a BCA are typically a blend of impacts experienced by all customers, by society, by broad customer categories, or by host customers. Therefore, the bottom-line results of the BCA, in terms of net benefits or a benefit-cost ratio, cannot be broken out to indicate distributional effects across customers or on target populations.

The one exception to this limitation of BCAs is the Participant Cost Test, which measures the direct costs and benefits to DER host customers. In this case, there is no blending of impacts across all customers or multiple customer types: The Participant Cost Test includes the costs, benefits, and non-energy impacts to participants only. Thus, the Participant Cost Test can be used to indicate how DERs will affect host customers. However, even this would be a very limited indication of equity. It only shows whether DER host customers are better off with the DER. The Participant Cost Test provides no information regarding

[23] In some cases, utility system DER impacts might be passed on to specific customer classes, e.g., residential, commercial, and industrial classes. But these are very broad customer categorizations and do not address equity within these categories, nor do they address equity regarding target populations.

how DERs affect non-participants, nor does it provide any indication about impacts on target populations relative to other customers.[24]

9.3.2. Rate, Bill, and Participation Analyses

A better way to assess customer equity is through rate, bill, and participation analyses. These analyses provide information about the extent to which rates and bills might change for DER host customers relative to non-host customers. They also provide information about how many customers are host customers versus non-host customers. Because DER host customers typically experience greater benefits than non-host customers, customer participation rates provide very useful information about customer equity (see NSPM 2020 Appendix A).

> Because DER host customers typically experience greater benefits than non-host customers, customer participation rates provide very useful information about customer equity.

Consistent with NSPM principles, it is important to keep rate, bill, and participation analyses separate from BCAs because they answer fundamentally different questions:

- BCAs typically address the question of which DERs will have net benefits across customers and perhaps society on average, and therefore might merit utility acquisition or support on behalf of all customers.
- Rate, bill, and participation analyses address the question of whether and how much will DERs increase or reduce rates for host customers and non-host customers. They also address the question of what portion of customers will be host customers and thereby experience greater benefits than non-host customers. This provides very useful information regarding equity between host and non-host customers.

However, rate, bill, and participation analyses do not address a key aspect of energy equity: They do not provide information on how the costs and benefits of DERs are distributed between target populations and other customers. Further, comprehensive rate, bill, and participation analyses have not been used by many jurisdictions to date, and therefore have not yet fulfilled their potential for providing even a limited equity analysis.

Table 81 presents a summary of how both BCAs and rate, bill, and participation analyses are limited in the way that they address distributional impacts on target populations.

[24] Further, the Participant Cost Test is not an appropriate test to use for making decisions regarding which DERs merit utility investment on behalf of customers. It is best used for program design purposes (see NSPM 2020, pages E-4 and E-5).

Table 81. Limitations of BCAs and rate, bill, and participation analyses in addressing equity

Type of Analysis	Method	Limitations
Benefit-Cost Analyses	Account for host customer impacts in a BCA test	• Results include a blend of costs and benefits across all customers and several customer types • Does not distinguish between host customers in a target population versus other customers
	Account for societal impacts in a BCA test	• Results include a blend of costs and benefits across all customers and several customer types • Does not distinguish between societal impacts on average versus those that affect target populations
	Account for *only* participant (host customer) impacts in BCA, i.e., use Participant Cost Test	• Does not provide information on non-participants • Does not provide information on target populations • Should not be used to inform utility investment decisions
Rate, Bill, and Participation Analyses	Review participation rates; assess associated rate and bill impacts on host and non-host customers to ensure they are not unduly high or inequitable	• Conventionally, these have not considered the rates, bills, and participation impacts on target populations

9.3.3. Distributional Equity Analysis

Distributional equity analyses can explicitly account for the difference in impacts between target populations and other customers.

Distributional equity analyses (DEAs) can be used to address the limitations of BCAs and rate, bill, and participation analyses in assessing energy equity. DEAs can explicitly account for the difference in impacts between target populations and other customers.

DEAs ideally should start with a conventional rate, bill, and participation analysis and expand on it as follows:

- Expand the rate, bill, and participation analysis to compare these impacts on target populations versus other customers.
- Add additional equity metrics such as energy burden, customer arrearages, etc.
- Assess the distribution of specific DER impacts between target populations and general customers. This might include, for example, an assessment of service reliability to target populations versus other customers, or of the public health impacts on target populations versus other customers.

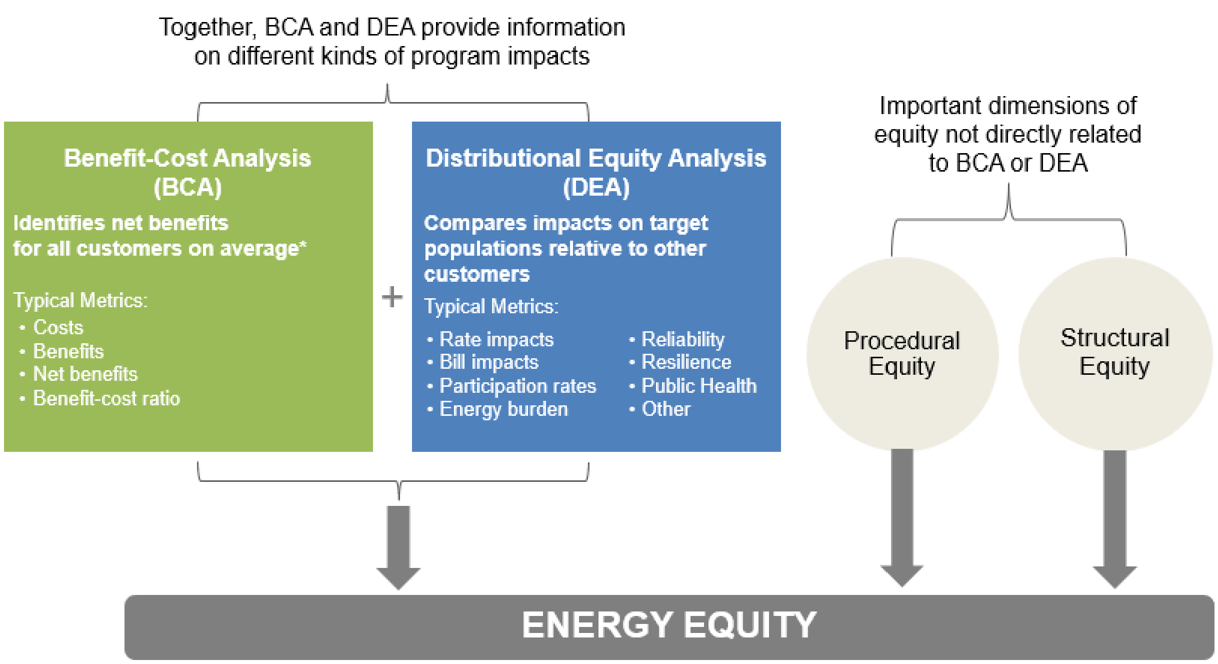
Like BCAs, DEAs should be designed to address the policy goals of the jurisdiction. The definition of target populations, the choice of equity metrics, and the specific impacts to calculate distributional effects for, should all be based on how the jurisdiction wants to address equity.

BCAs and DEAs are complementary. They should be conducted in parallel, using consistent inputs and assumptions. The results of the two analyses, however, should be presented side-by-side for decision making purposes (see NYU IPI 2022). BCAs and DEAs use different metrics: BCAs present results in terms of net benefits or benefit-cost ratios for customers and perhaps society on average, while DEAs present results in terms of rate impacts, bill impacts, DER participation, energy burden, customer arrearages, reliability, resilience, public health, and other metrics as warranted. BCAs and DEAs also answer fundamentally different questions: BCAs answer the question of how DERs affect customers and perhaps society on average, while DEAs answer the question of how DERs affect target populations relative to other customers. If BCAs and DEAs are combined somehow, then it is very difficult to answer either of these questions.

BCAs and DEAs are complementary. They should be conducted in parallel, using consistent inputs and assumptions. The results of the two analyses, however, should be presented side-by-side for decision-making purposes.

Figure 41 provides a conceptual framework for how BCAs combined with DEAs can address energy equity issues and inform utility investment decisions. It also indicates how the procedural and structural dimensions of equity are not directly related to BCA practices.

Figure 41. Energy equity and benefit-cost analysis



** Non-utility system impacts can be accounted for in BCAs if consistent with the jurisdiction's policy goals, but inclusion of these impacts in BCA does not provide a measure of equity across target populations.*

Table 82 presents a high-level comparison of BCAs, Rate, Bill, and Participation Analyses, and DEAs. It indicates how they serve different purposes, address different questions, and use different metrics to report the results.

Table 82. High-level comparison of BCAs, rate, bill, and participation analyses, and DEAs

	Benefit Cost Analysis	Rate, Bill, Participation Analysis	Distributional Equity Analysis
Purpose	To identify which DERs utilities should invest in or otherwise support on behalf of customers on average	To identify how DERs affect host versus non-host customers	To identify how DERs affect target populations versus other customers
Questions Answered	What are the costs and benefits of DERs across customers and perhaps society on average? What are the costs and benefits of a DER program designed for target populations?	What is the impact of DERs on host versus non-host customers?	What is the impact of DERs on target populations versus other customers?
Example Metrics for Reporting Results	Costs (PV$) Benefits (PV$) Net benefits (PV$) Benefit-cost ratios	Rate Impacts ($/kWh) Bill Impacts ($/month) Participation rates (% of eligible customers)	Rate Impacts ($/kWh) Bill Impacts ($/month) Participation rates (% of eligible) Additional Impacts on target population: • Energy burden • Reliability • Resilience • Public health • Other

Although this conceptual framework may be new to electric and gas utility BCAs to date, distributional analyses are frequently conducted by federal agencies as part of regulatory BCA. Agencies like the EPA include distributional analyses as part of their broader regulatory impact analyses when proposing new regulations (see NCEE 2014, Chapter 10). Separately, the New York University Institute of Policy Integrity has developed guidance on the procedures and methodologies that the Office of Management and Budget (OMB) could apply to account for equity in the regulatory review process, with a focus on environmental injustice (see NYU IPI 2021; NYU IPI 2022).

9.3.4. BCA and Intergenerational Equity

As noted above, intergenerational equity is one aspect of distributional equity. Intergenerational equity addresses the concept of fairness among current and future customers regarding the costs and benefits of energy resources.

Intergenerational equity can be addressed, in part, by using a study period for the BCA that is long enough to capture the full lifetime costs and benefits of a DER (see NSPM 2020, Principle #5). In this way, the BCA accounts for the costs and benefits of all customers over the operating life of the DER.

However, it is common practice to apply a discount rate to the costs and benefits of a BCA, which places greater weight on the costs and benefits in the short term relative to the long term. As described in the NSPM:

> The discount rate reflects a particular "time preference," which is the relative importance of short- versus long-term impacts. A higher discount rate gives more weight to short-term benefits and costs relative to long-term benefits and costs, while a

> lower discount rate weighs short-term and long-term impacts more equally (see NSPM 2020, Appendix G, page G-1).
>
> The choice of discount rate is a decision that should be informed by the jurisdiction's applicable policy goals. Therefore, the regulatory perspective should be used to determine the appropriate discount rate (see NSPM 2020, Appendix G, page G-1).

If a jurisdiction has a policy goal to improve, or at least not worsen, intergenerational equity, then the regulators in that jurisdiction should lean towards applying a lower discount rate than they might otherwise apply. Intergenerational equity would be one of the many factors that regulators should use in determining a discount rate. (For a summary of the process that regulators should use, and the factors to consider, in determining a discount rate, see NSPM 2020, Appendix G, Section G.5.)

Further, there are some impacts of electricity and gas resources that have more long-term implications than others. GHG emissions, in particular, are likely to have greater impact over the long term than the short term. If a jurisdiction has a policy goal to address intergenerational equity with regard to climate impacts, then the choice of discount rate used to determine the benefits of reducing GHG emission will have important intergenerational equity implications.

9.3.5. Challenges and Additional Considerations

As stated above, this chapter represents a conceptual framework on how BCAs can be used to assess whether DERs can advance energy equity goals. More work remains to be done to develop specific methodologies and best practices for conducting and using DEAs in decision-making alongside BCAs. Additional research is necessary to answer at least the following questions:

- How should target populations be defined for the purpose of BCAs and DEAs?
- How should utilities collect more granular customer demographic data to identify target populations and create a baseline understanding of the target populations? Who should collect this data and who should it be shared with? How to protect customer privacy while collecting data on individual utility customers?
- How to construct a DEA? Which energy equity metrics should be used in conducting DEAs?
- How should DEA results be presented to decision-makers? For each DER program separately? For portfolios of programs for each DER type? For all DER programs combined?
- How should the BCA and DEA results be used together to make resource investment decisions? What should be done if a highly cost-effective DER is shown to be inequitable through DEA? What should be done if a DER is not cost-effective but offers important equity benefits?
- Should regulators establish thresholds, principles, parameters, or specific frameworks for comparing the monetary results of a BCA to the non-monetary results of a DEA?
- How can BCAs and DEAs be used to assess the *relative magnitude* of costs and benefits to target populations compared to other customers? In other words, how to account for the fact that one dollar to a customer in the target population might be worth a lot more than one dollar to other customers?
- How can jurisdictions use BCAs and DEAs to shed light on the cost of underinvesting in target populations?
- How should DEAs be used to influence DER program design?

9.4. Resources for Addressing Energy Equity

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Energy Equity Project. n.d. energyequityproject.com website. https://energyequityproject.com/

Illume Advising. 2021. *The Energy Equity Playbook*. https://illumeadvising.com/files/The.Energy.Equity.Playbook.pdf

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U.S. Environmental Protection Agency. 2021. (U.S. EPA 2020 O&G). "Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review". https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsps-eg-climate-review_0.pdf

VEIC. 2019. *The State Of Equity Measurement: A Review of Practices in the Clean Energy Industry*. Levin, Palchak, Stephenson. https://www.veic.org/Media/default/documents/resources/reports/equity_measurement_clean_energy_industry.pdf

10. UNCERTAINTY AND RISK

There are many methods that can be used to account for uncertainty and risk in the context of electric and gas utility BCAs and long-term planning in general. These methods typically draw upon practices used in other fields, where extensive work has been done to develop sophisticated approaches to this complex challenge. This chapter summarizes some of those methods at a high level and provides several examples of studies assessing uncertainty and risk in the context of utility planning.

Readers seeking more in-depth guidance on how to account for uncertainty and risk in utility planning are encouraged to review the resources listed in Section 10.6.

10.1. Definitions

10.1.1. Uncertainty and Risk

All analyses of future costs and benefits will include some degree of uncertainty and therefore risk. The goal of a BCA is to provide the information needed to make sound decisions regarding resource investments, despite the uncertainty inherent in resource planning. The value of structured approaches for assessing risk and uncertainty is becoming increasingly apparent in demand-side and supply-side resource assessments.

In the context of planning, *uncertainty* is defined as the situation where the "correct" or "exact" value of a parameter is not known or cannot be known (EPRI 2015).

In the context of planning, *risk* is defined as an adverse outcome that can occur with some degree of probability. In statistical terms, risk is the expected value of a potential loss (CERES 2012). Risk is defined by the relationship:

$$Risk = probability\ of\ the\ outcome\ occurring * the\ cost\ of\ the\ outcome$$

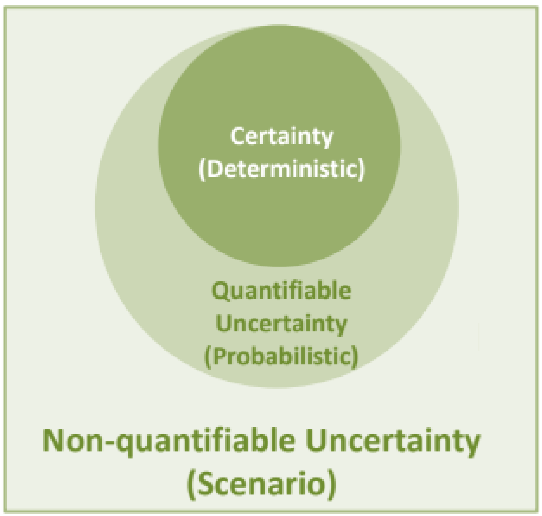
Uncertainty and risk are linked in that uncertainty is what creates the potential for a variety of different outcomes, each with its own probability of occurring. There can also be uncertainty in the costs associated with each such outcome.

For planning and decision-making purposes, there is an additional distinction between uncertainty and risk. Decision-making can be divided into three categories (EPRI 2015):

- Decision under certainty. This is when a decision is made with "perfect" knowledge, where all inputs and assumptions are assumed to be correct. For BCA inputs that are assumed to be certain enough, no additional risk analysis is required. This is referred to as deterministic analysis and decision-making.
- Decision under risk. This is when a decision is made by quantifying the uncertainty and assigning quantitative values to the probability of the outcome occurring and the cost of the outcome. For inputs where reasonable uncertainties can be quantified, probabilistic analysis and decision-making can be applied.
- Decision under uncertainty. This is when there is no, or very little, quantitative knowledge of uncertainties or probabilities. For inputs that are this uncertain, alternative assessments can be applied, including sensitivity and scenario analyses.

Figure 42 presents the relationship between decision-making under certainty, risk, and uncertainty. In the context of electric and gas utility BCAs, all three of these categories are relevant: some inputs can be developed with a reasonable degree of certainty; some inputs are uncertain but can be analyzed using quantitative data; and some inputs are uncertain but are much harder to assign quantitative probabilities to.

Figure 42. Decision-making under certainty, risk, and uncertainty



Source: Adapted from EPRI 2015, page 3-30, Figure 3-1.

There may not be clear distinctions between which inputs are certain, are uncertain but quantifiable, or are uncertain and not quantifiable. Over time, as additional information is collected and analyzed, inputs that were once considered non-quantifiable, might become quantifiable, and might even become certain enough to eliminate the need for uncertainty or risk analysis.

There is a long list of factors that introduce uncertainty into electric and gas utility planning processes. This includes uncertainties associated with power plant siting, cost, and availability; transmission and distribution facilities siting, cost, and availability; fuel prices; customer energy demand; customer regulatory demand; costs and operating performance of DERs; customer response to DER programs; regulatory and policy shifts; environmental regulations; and more.

The choice of method for addressing uncertainty and risk will depend upon the quality and reliability of the information available at the time of the BCA. Some inputs to a BCA, such as the cost of a DER program in the first year, might be deemed to be certain enough that no additional risk analysis is needed. Some inputs, such as the likelihood of a new environmental regulation, might be deemed to be certain enough to attach a quantitative probability to and to be subject to probabilistic techniques. Other inputs, such as the price of natural gas over the next 20 years, might be deemed to be more challenging to apply a single quantitative probability to and therefore subject to other techniques such as scenario analyses.

10.1.2. Resource Risk and Planning Risk

For the purposes of BCAs, it is useful to be aware of the distinction between resource and planning risk.

10.1.2.a. Resource Risk

Resource risk refers to the risk benefits (or costs) of specific utility resources: generation, transmission, distribution, and DERs.[25] Examples of resource risk associated with DERs, relative to traditional supply-side alternatives, include (see ACEEE 2020 Three Rs; RMI 2017):

- Reduced risk due to reduced reliance on fossil fuels that can be subject to limited availability and fluctuating prices. On the other hand, those DERs that result in a *net increase* in fossil fuel use can lead to a *net increase* in the risk of associated with fossil fuels.
- Reduced risk resulting from a large number of smaller distributed resources reducing risk of resource performance failure (if one DER fails it will have a much smaller impact on the system compared with one large generation or transmission failure).
- Reduced risk due to modular DERs' ability to reduce reliance on long lead-time generation, transmission, and distribution investments, thereby creating "option value" that reduces the risk that such investments may not ultimately be needed as conditions change over time.
- Reduced risk of costs of compliance with climate or environmental policies. On the other hand, those DERs that result in a *net increase* in air emissions can lead to a *net increase* in the risk of compliance with environmental requirements.
- Reduced risk due to the demand flexibility provided by DERs, especially to address operational requirements of large-scale intermittent resources.
- Either increased or decreased cybersecurity risk that DERs can provide to the utility system.

All utility resource options can have both positive and negative resource risks. For example, a DER might reduce risks associated with fossil fuel price volatility but increase risks associated with customer adoption and operating performance of the DER technology. It is important, therefore, to account for both the increased and reduced risks of resources, i.e., the *net* resource risk impacts. The extent to which DERs increase or decrease risk to the utility system will depend on the DER type (e.g., energy efficiency, demand response, distributed solar and storage, electrification, or some combination) and the specific use case.

In addition, risks associated with any one utility resource should be determined relative to the risks associated with alternative resources. For example, when estimating the performance risk of a DER in a BCA, that risk should be compared with the performance risk of the resources avoided by the DER.

In the context of BCAs, a net *reduction* in risk should be considered a risk benefit of the proposed resource, and a net *increase* in risk should be considered a risk cost of the proposed resource.

Section 10.4 provides examples of jurisdictions that require energy efficiency program administrators to account for risk in their energy efficiency BCAs. All of these examples pertain to resource risk and require program administrators to assign a specific risk benefit to energy efficiency resources.

[25] Resource risk is sometimes referred to as "portfolio" risk because it represents the risk effect of one resource relative to the entire portfolio of resources.

10.1.2.b. Planning Risk

Planning risk refers to the risks caused by the uncertainties inherent in any forecasting and planning exercise. Planning risk is driven by the uncertainty around the estimated inputs and related forecasts in the BCA and can affect many aspects of a BCA and many different resource types considered in the BCA.

Examples of uncertainties that create planning risk include those related to electricity demand forecasts; gas demand forecasts; fossil fuel price forecasts; siting and construction of energy facilities; environmental requirements; and more.

10.1.2.c. Resource Versus Planning Risk

Note that there is overlap between resource risk and planning risk. For example, the inherent uncertainty in fuel price forecasts creates a resource risk benefit for DERs.

Resource risk is commonly addressed using methods for addressing *quantifiable* uncertainties (see Section 10.3.1), and planning risk is commonly addressed using methods for addressing *unquantifiable* uncertainties (see Section 10.3.2), but either method can be used to address either kind of risk.

Ideally, both types of risk should be accounted for in conducting BCAs. If this is done, then it is important to avoid double-counting risk impacts.

10.2. The Importance of Accounting for Uncertainty and Risk in BCAs

Utility decisions about what types of resources to acquire, in what amounts, and at what times are complicated by uncertain and sometimes incomplete information. These uncertainties concern the resources themselves (e.g., installation costs, operating costs, and performance) and the external environment (e.g., environmental regulations, economic growth, fossil-fuel prices, and consumer demand for energy). Utilities have made progress during the past several years in developing and applying improved methods to treat uncertainty. These methods include applications of sensitivity, scenario, portfolio, and decision-analysis methods. Risk assessment methods used by IRP studies in the 1990s are being re-discovered and updated to meet the new challenges of a distributed energy future.

A NARUC risk workshop report concluded that one of the key lessons learned was that workshop participants using "risk informed perspectives performed better than those who used intuition and judgement," and that "asking fundamental risk-oriented questions helped the best teams clarify their challenges and identify better management strategies" (see NARUC 2016).

The key messages from this and other recent studies are (a) all plans face uncertainty in inputs and outputs, and (b) addressing uncertainty and risk as part of the planning process will lead to better decisions and better outcomes.

Uncertainty is present in every long-term utility planning process, and *not* taking systematic approaches for assessing uncertainty may be the equivalent of assuming that there is no uncertainty, which is clearly incorrect. Research shows that addressing uncertainty and risk using basic approaches improves the quality of decision-making and helps ensure that monies invested are likely to produce the expected benefits. It also helps avoid heuristic biases in decision-making such as staying with the status quo.

Appropriately assessing risk and uncertainty helps appraise what is known and where there are gaps in the information. This can help in defining program and policy implementation by setting out what needs to be tracked over time to measure progress towards goals, and to incorporate continuous learning as additional information is gathered.

10.3. Methods for Addressing Uncertainty and Risk

10.3.1. Quantifiable Uncertainty

Quantifiable uncertainties are those where probabilities and probability distributions can be calculated. A clear example of a quantifiable, calculable probability would be the likelihood of a given number coming up on the roll of a die, where each side has a probability of 1 out of 6 occurring even though there is uncertainty around which number will actually come up.

BCA inputs that fall in this category include, for example, system load, hydro output, weather-related variability in renewable generation, and performance characteristics of generation facilities. Inputs with this type of uncertainty can be addressed using probability distributions (see EPRI 2015, page 1-6, Figure 1-1).

There are many techniques available to address uncertainty that can be reasonably quantified. These methods are the most common approaches for addressing *resource* risk but can also be used to address *planning* risk.

One useful construct is the loss function. The loss function examines the costs associated with the assumption that one set of inputs is presumed to be "true" when in fact another set of values are correct. This approach simply looks at the cost of being wrong. This approach helps understand the relative robustness of decisions to invest in different resources or combinations of resources. The loss function can be quantified with this risk formula, also described above:

$$Risk = probability\ of\ the\ outcome\ occurring * the\ cost\ of\ the\ outcome$$

The inputs to this formula are often not well known. In these cases, a hedge value approach can used to estimate the cost of avoiding a risk by making an alternative investment or buying an alternative product that reduces or eliminates the risk of the investment in question. The alternative investment or product does not need to be procured in order to reduce or eliminate the risk; instead, the cost of the alternative is used to indicate the risk associated with the investment in question. In other words, the cost of the hedge is used as a proxy for the risk benefit.

For example, if a renewable resource is able to reduce the risk associated with natural gas price volatility, then that reduction in volatility can be quantified and monetized by identifying a hedge that could actually be purchased on the market that would achieve the same reduction in risk. Financial hedging instruments, such as the price of a 10-year natural gas swap (i.e., what it costs to lock in prices over the next 10 years), can be used for this purpose. The value of such a hedge, in dollars, can then be considered a risk reduction benefit associated with that renewable resource.

Example Study: In a 2002 study, Lawrence Berkeley National Laboratory found that energy efficiency and renewable energy can serve as a hedge against volatile natural gas costs (see Bolinger et al. 2002). The research examined the cost of hedging gas price risk through financial hedging instruments by looking at the price of a 10-year natural gas swap (i.e., what it costs to lock in prices over the next 10 years). The study found that the incremental cost to hedge gas price risk exposure is potentially large enough—particularly if incorporated by policymakers and regulators into decision-making practices such as BCA—to tip the scales away from new investments in variable-price, natural gas-fired generation and in favor of fixed-price investments in energy efficiency and renewable energy.

The quantifiable risks in this category are sometimes referred to as “insurable” risks, which means that it is possible to identify and quantify hedge values that could be used to insure against the risk. The unquantifiable risks (described in the following section) are sometimes referred to as “uninsurable” risks because there is not enough quantitative information to determine how to hedge against them (EPRI 2015).

Several examples of jurisdictions that use this method are provided in Section 10.3.3 Table 1.

10.3.2. Unquantifiable or Judgmental Uncertainty

Unquantifiable, or judgmental, uncertainty refers to uncertainty that is especially hard to quantify using probability distributions. In the absence of probabilities, some amount of professional judgment is necessary to address this type of uncertainty. BCA inputs that fall into this category include, for example, long-term economic activities, long-term fuel price variations, changes in supply-side and DER technologies, and changes in laws or regulatory policies (see EPRI 2015, page 1-6, Figure 1-1).

Many approaches are available to address judgmental uncertainties that are hard to quantify. Three primary options are described below. These methods are the most common approaches to addressing *planning* risk but can also be used to address *resource* risk. In many analyses, all three of these methods are used. Sensitivity analyses is typically the first step and is then augmented by scenario analyses to capture interdependences, which then sets the stage for likelihood analyses.

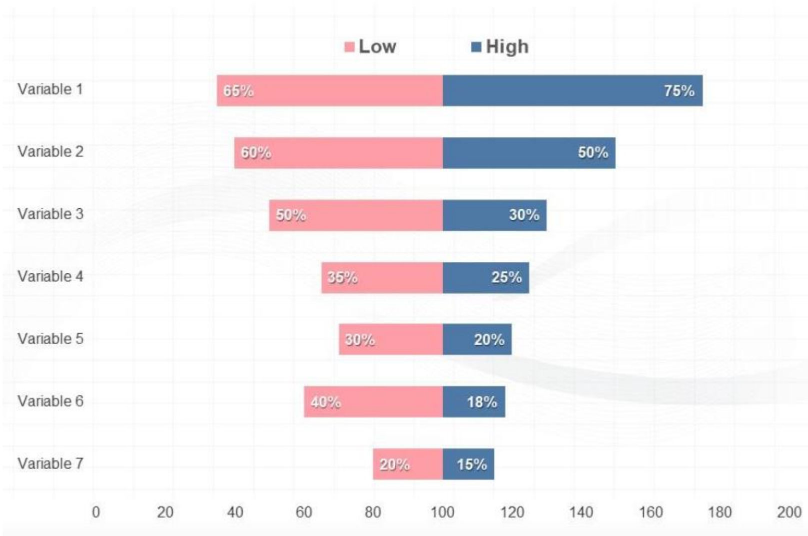
Option 1. Sensitivity Analyses

Sensitivity analyses look at how benefits and costs are impacted by different inputs or modeling assumptions. The goal is to determine which inputs or modeling assumptions have the largest impact on the benefit-cost values, and what that impact might be (see UNESCO 2005).

Sensitivity analyses include changing one input assumption at a time to see how those input assumptions are likely to affect the benefits and costs. This typically involves changing key inputs by a given amount, for instance, looking at how an increase or decrease in input values impacts the benefits and costs in the analysis. This could be done for +/- 20% and +/-50% changes in input values, for example.

A tornado diagram is a standard way to present the results of sensitivity analyses across a number of inputs. Figure 43 below presents an example of a tornado diagram, showing the results from low and high values for each variable analyzed.

Figure 43. Example tornado diagram for sensitivity analyses



This one-at-a-time approach to accounting for uncertainty is admittedly limited. It does not address questions about non-linearities, asymmetrical risks, and correlations across risks where there is a likelihood that multiple higher than expected outcomes in will move in the same direction (see Czitrom 1999). If these issues are expected to have a significant effect on the outcome, then scenario analysis may be a better method than sensitivity analysis.

Option 2. Scenario Analyses

Scenario analyses can be used to build on and extend sensitivity analyses. They involve building scenarios that account for changes across multiple inputs based upon a specific future outlook or forecasting perspective.

Each scenario should be based on a coherent and internally consistent set of assumptions about key relationships and driving forces (see Spaniol and Rowland 2018). Alternative scenarios may be used as alternative model formulations, as alternative sets of input data, or as both (see Walker et al. 2003).

There are a variety of scenarios that might be useful when conducting BCAs for DERs. For example:

- A high (or low) fuel price scenario, where *all* fuel prices are higher (or lower) than the base case, which would affect not only avoided costs of DERs, but also electricity and gas demand, and electricity and gas prices.
- An advanced technology scenario, where many technologies are assumed to evolve more rapidly than the base case, which would affect not only the cost of DERs but also the performance assumptions, the availability, and the customer adoption of DERs.
- A decarbonization scenario, where more stringent climate change regulations than the base case are assumed, which would affect many elements in a BCA such as fuel prices, electricity and gas prices, electricity and gas demand, the advancement of clean energy technologies, retirement of fossil-fuel resources, and more.

The key issue in designing scenarios such as these is to account for all the different inputs that might be affected by the scenario assumptions, not just how a single input might be affected as is done with sensitivity analyses.

> **Example:** A 2005 LBNL study looked at actual utility resource plans that included significant amounts of renewable energy additions. The planned additions—primarily coming from wind power—were motivated by the improved economics of wind power, and an increasing recognition of the inherent risks (e.g., natural gas price risk, environmental compliance risk) in fossil-based generation portfolios. The report examined how 12 western utilities treated renewable energy in their resource plans including the utilities' analysis of natural gas price and environmental compliance risks and examined how the utilities traded off portfolio cost and risk in selecting a preferred portfolio (see Bolinger and Wiser 2005).

Option 3. Likelihood Analyses

Likelihood analyses can be used to prioritize and refine sensitivity and scenario analyses. Likelihood analyses look at how likely different sensitivity assumptions and scenarios are to occur. This involves using as much information as is available to assign probabilities to the key uncertainties in the BCA. If it can be determined that a particular uncertain outcome is extremely unlikely, or that a particular value considered for a sensitivity or scenario is extremely unlikely, then these extremely unlikely outcomes can be given much lower priority in the BCA uncertainty analyses.

One notable exception to this concept is for outcomes that might be extremely unlikely but have a very high cost associated with it, such as severe weather events or aggressive cybersecurity attacks. Remember that risk is the product of the probability and the cost of the outcome. In some cases where the probability is low, the cost of the outcome might be so great as to make it worth accounting for in the BCA uncertainty analysis.

Some methods for quantifying probabilities for this purpose are described in the following section.

10.3.3. Quantifying Uncertainty Using Professional Judgment

Planning exercises sometimes use techniques that rely upon professional judgment to quantify the uncertainty associated with key planning inputs and parameters (see EPRI 2015; Walker et. al., 2003). This requires the use of informed expert opinions to determine a reasonable estimate of likelihoods associated with key uncertainties.[26]

This "professional judgement" approach typically begins with defining the "pivot factors" in the planning analysis. These are factors that are expected to have a significant impact on the analysis and/or a high degree of uncertainty.

The next step involves estimating probabilities associated with the pivot factors. These probabilities are developed by relying upon experts familiar with utility planning and the pivot factors of interest.

[26] Some studies refer to this approach as using "subjective judgment" (see EPRI 2015). Subjective is defined as being based on a personal interpretation of data, while objective is defined as being based on factual data. The term "professional judgment" is used in this handbook because estimates of the likelihoods of uncertainties can be based on a combination of factual information and expert interpretation of that information.

Sometimes this is limited to experts from the utility, stakeholders, regulators, and consultants involved in the BCA or long-term planning process.

This method can also include input from select people from outside the planning process, if it is believed that additional insights will be valuable. For example, regional experts that have insights into the economic growth, population/customer growth, and forecasts of energy prices have been used in past efforts. In addition, if specific DER technologies (e.g., storage, PVs, heat pumps, etc.) are important to the BCA outputs, having technology experts provide information on the range of performance and/or the costs of operation of these technologies can be useful.[27]

It is important to recognize that professional judgment should be informed by the specific context of the BCA. This includes developing context around BCA outcomes by examining the range and likelihoods for different pivot factors. In other words, the experts used in this method should be apprised of all the factors in the BCA that might affect uncertainty.

Professional judgment can also be used to establish reasonable lower and upper bounds (i.e., a range of outcomes) of key uncertain pivot factors. These estimates should be accompanied by a description of the factors that drive the bounding estimates: What causes the lower bound value and the upper bound value? They should also include a discussion of where, within the range, the most likely outcome is expected to fall. These results would lead to high, medium, and low cases, with probabilities ascribed to each case.

This method, while approximate because it is based on judgment in the face of uncertainty, offers several benefits:

- Reducing potential biases that can occur in long-term planning analyses.
- Promoting better decision-making by accounting for uncertainty more directly and transparently.
- Providing insights into what actions can be taken to manage the risks. By better understanding the factors driving uncertainty, actions can be taken to manage outcomes or create options that allow for learning over time and sequential decision-making.
- Offering a relatively low-cost way to account for uncertainty.

10.4. Jurisdictions that Account for Risk Impacts

While there are well documented risk benefits of DERs, in particular for energy efficiency, not many jurisdictions account for these benefits in their BCAs. This is largely because of the complexity of quantifying the reduced risk. Table 83 shows where states account for risk, and the general approach or methodologies used to quantify a risk value for inclusion in the BCA (see ACEEE 2020 Three Rs).

[27] This method is sometimes referred to as the Delphi approach because it relies upon a panel of experts whose combined knowledge represents the best available insights on how to forecast the future.

Table 83. Examples of jurisdictions that require accounting for energy efficiency risk benefits

Entity	Value of reduced risk from efficiency	General Approach
District of Columbia Sustainable Energy Utility	5%	Proxy for the value of reduced risk as an adder to the other benefits of energy efficiency (see DC SEU 2016)
Maryland	\$0.007/kWh	Included as an adder to avoided cost of energy calculation to reflect the avoided costs of both avoided business risks and avoided ancillary services
NW Natural	\$0.37/MMBTU	Levelized average fuel-price risk avoidance used in integrated resource planning and cost-effectiveness testing for natural gas energy efficiency (see NW Natural 2018)
Northwest Power and Conservation Council	\$0.02/kWh	Accounting for reduced risk of efficiency in utility resource planning compared to other resource options (see ETO 2107)
Pacific Power	\$0.00145/kWh	Levelized average fuel-price risk avoidance used in integrated resource planning and cost-effectiveness testing (see ETO 2017)
Portland General Electric	\$0.0058/kWh	Levelized average fuel-price risk avoidance used in integrated resource planning and cost-effectiveness testing (see ETO 2017)
Vermont	5% - 10%	Costs of gas DERs are reduced by 10% and costs of electricity DERs are reduced by 5% to reflect the net risk reduction benefits of DERs (see VT PUC 2020)

Source: ACEEE 2020 Three Rs, pages 10-11, Table 1.

The predominate approach used to account for resource risk in the table above is to recognize the price hedge value of DERs using the Quantifiable Uncertainty approach described in Section 10.3.1. For example, the Energy Trust of Oregon has developed estimates of the costs of hedging fossil fuels and used those costs to develop a "risk reduction value" as an adder to its estimates of future electric and gas avoided costs used to value energy savings from efficiency measures and programs (see ETO 2017).

In the case of Vermont, the Commission has established proxies to account for the risk benefits associated with demand-side options. The risk proxies are based on reviews of risk analyses in other parts of the country and on proposals made by intervenors in Vermont dockets. The proxies are ultimately decided upon by the Commission. The original risk proxy reflected the energy efficiency resource risk benefits of “flexibility, short lead time, availability in small increments, and ability to grow with load” (see VT PUC 1990). The proxy is applied by reducing the cost of energy efficiency measures by a pre-determined percentage. At first, the proxy was set at 10 percent to reflect the risk benefits of all energy efficiency programs relative to supply-side alternatives. Recently, the Commission recognized that the risk benefits of electric efficiency measures are somewhat muted by the wholesale electricity market in New England, and therefore modified the risk proxy for electricity energy efficiency to 5 percent but kept the risk proxy for gas energy efficiency at 10 percent. Further, the VT Commission now applies these risk benefit proxies to all demand-side resources (see VT PUC 2020, page 46).

10.5. Further Research

As stated above, this chapter provides a high-level summary of concepts that can be used to account for risk in BCAs. While there is substantial information available on how to address risk in long-term utility planning, as indicated in the following section, further research would significantly enhance practices regarding how risk techniques can be applied to BCAs for DERs. For example, additional research could help with the following questions:

- In what ways do DERs create resource risk benefits or risk costs, beyond those identified to date for DERs?
- What are the best techniques for quantifying and monetizing resource risks?
- What are the best techniques for addressing planning risk in utility BCAs for DERs?
- Can some of these techniques be simplified to make them more readily accessible and usable for BCA practitioners?
- Can proxies for resource risks be developed for each DER type to allow for easy and quick application in BCAs for DERs in any jurisdiction?

10.6. Resources for Accounting for Uncertainty and Risk

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11. LOAD IMPACT PROFILES

11.1. Introduction and Definitions

This chapter addresses methods, tools, and resources for developing load impact profiles—also referred to as load impact *shapes* or *operating profiles*—for the full range of DERs in the NSPM.[28] This is the “Determine DER Impact on Customer Load Profiles” step in the process diagram shown in Figure 1.

Load impact profiles are needed to convey, assess, and optimize the **temporal nature of DER options**. In the simplest use of load impact profiles in benefits analysis, the incremental DER load impacts are multiplied by incremental avoided costs for each time interval to estimate the value of the DER impacts for use in a BCA (see Section 2.8). However, load impact profiles are applied in different ways in more complex analysis. For example, when capacity expansion modeling is used to quantify generation costs, the DER load impact profile might be used as an input to the model to develop a DER case forecast of costs (see Sections 3.2.1and 3.2.2 for more details). In addition, the Constrained Optimization Modeling method in Section 11.2 optimizes DER impacts based on costs and other priorities so the valuation of DER impacts may occur within the model. This type of optimization includes cases where the temporal pattern of avoided costs would be used to dispatch the DER and, therefore, would be the basis of the load impact profile.

Development of DER load impact profiles generally involves analyzing two types of profiles:

- **Reference Case load profile:** This load profile represents what would happen in the absence of the DER(s) being evaluated in the BCA. That is, it is the expected load without the incremental effects of the DER(s) being considered. The Reference Case should include effects from all other types of DERs known to be or assumed to be present in the utility system. Therefore, the ordering of DERs is important since those being evaluated will be valued *after* the impacts of other DERs included in the Reference Case. The Reference Case load profile could be developed at one or more levels (end-use, whole-building, customer class, planning area, utility system, etc.).
- **DER Case load profile:** This is the load profile that includes the incremental impacts from the one or more DERs being evaluated.[29] It could be developed to analyze an individual type of DER independently (single-DER analysis), or multiple DER types and profiles in combination (multiple-DER analysis). Analysis of multiple DER types in combination should consider resource interactions (see Section 11.2.2). Regardless of the amount of DERs assumed in the DER Case, the DERs included should ideally be optimized to meet policy objectives or grid needs (e.g., minimize utility system cost, minimize GHG emissions, minimize customer costs, avoid or defer traditional utility upgrades, improve resiliency, increase flexibility). Optimization is particularly applicable to dispatchable DERs.

The net difference between the Reference Case load profile and the DER Case load profile is referred to herein as the **DER load impact profile**. For some types of DERs (e.g., distributed generation), the DER

[28] Use of the term “load impact profile” is common for energy efficiency, electrification, and demand response resources, while “operating profile” is more commonly used for distributed generation and distributed storage.

[29] This handbook uses “one DER” or “single DER” to refer to one type of DER being analyzed for a group of customers.

load impact profile can be developed irrespective of the Reference Case and DER Case profiles. (For an example, see Section 11.4.1 which shows a simulated solar PV load impact profile that also represents the DER load impact profile.) But ultimately, the interest is in how the DERs affect the Reference Case.

Figure 44 and Figure 45 illustrate these different types of load profiles. In Figure 44, the DER under evaluation is distributed solar PV, which shows the impact of a single DER relative to the Reference Case (with no solar PV). Figure 45 provides a multi-DER example, where the Reference Case includes distributed solar PV that is already installed, and the DER Case includes estimated impacts from two other types of DERs that are being evaluated: energy efficiency and demand response, where interactions between energy efficiency and demand response have been taken into account by assuming the energy efficiency occurs before the demand response. In both examples, the net impact is a reduction in load.

Figure 44. Illustration of load profiles: reference case, DER case, and DER load impact (DER = Solar PV)

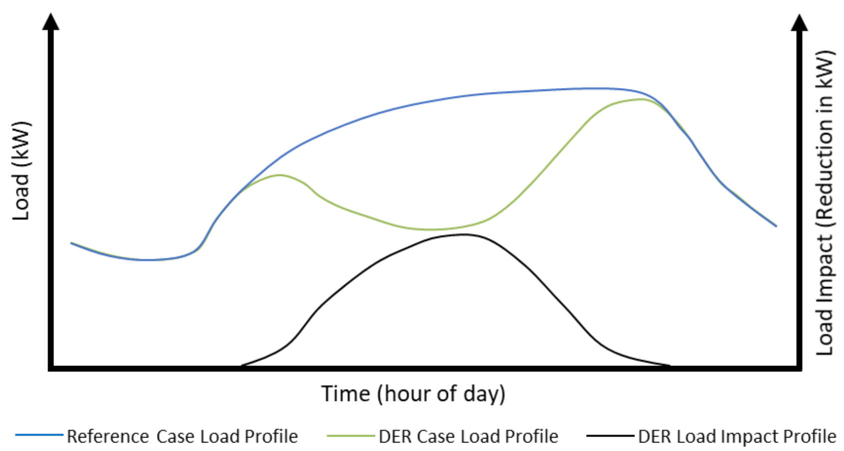
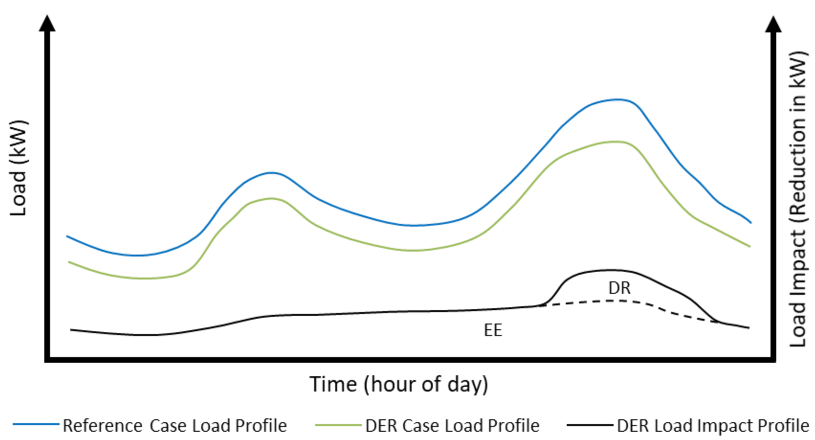


Figure 45. Illustration of load profiles: reference case, DER case, and DER load impact (DERs = EE+DR, interacted)



The remainder of this chapter is organized as follows:

- Section 11.2 describes methods for developing DER load impact profiles.
- Section 11.3 discusses applying the methods to different DER types by taking into consideration the unique load characteristics of each type of DER.

- Section 11.4 provides examples to illustrate some of the methods being used in practice.
- Section 11.5 lists examples of publicly available tools and resources to support development of DER load impact profiles.

11.2. Methods for Developing DER Load Impact Profiles

11.2.1. Overview

Developing DER load impact profiles involves the general process shown in Figure 46. To carry out the process, practitioners select from five main categories of methods: (1) simulation modeling, (2) submetering, (3) statistical approaches, (4) percent reductions, and (5) constrained optimization modeling. Within these main categories there are some subcategories with variations in approaches. In addition, several of these methods employ elements from one or more different methods. The methods described below can also be used together to form a “hybrid” approach for more complicated analysis, such as when evaluating multiple DERs in combination.

Figure 46. Overview for developing load impact profiles

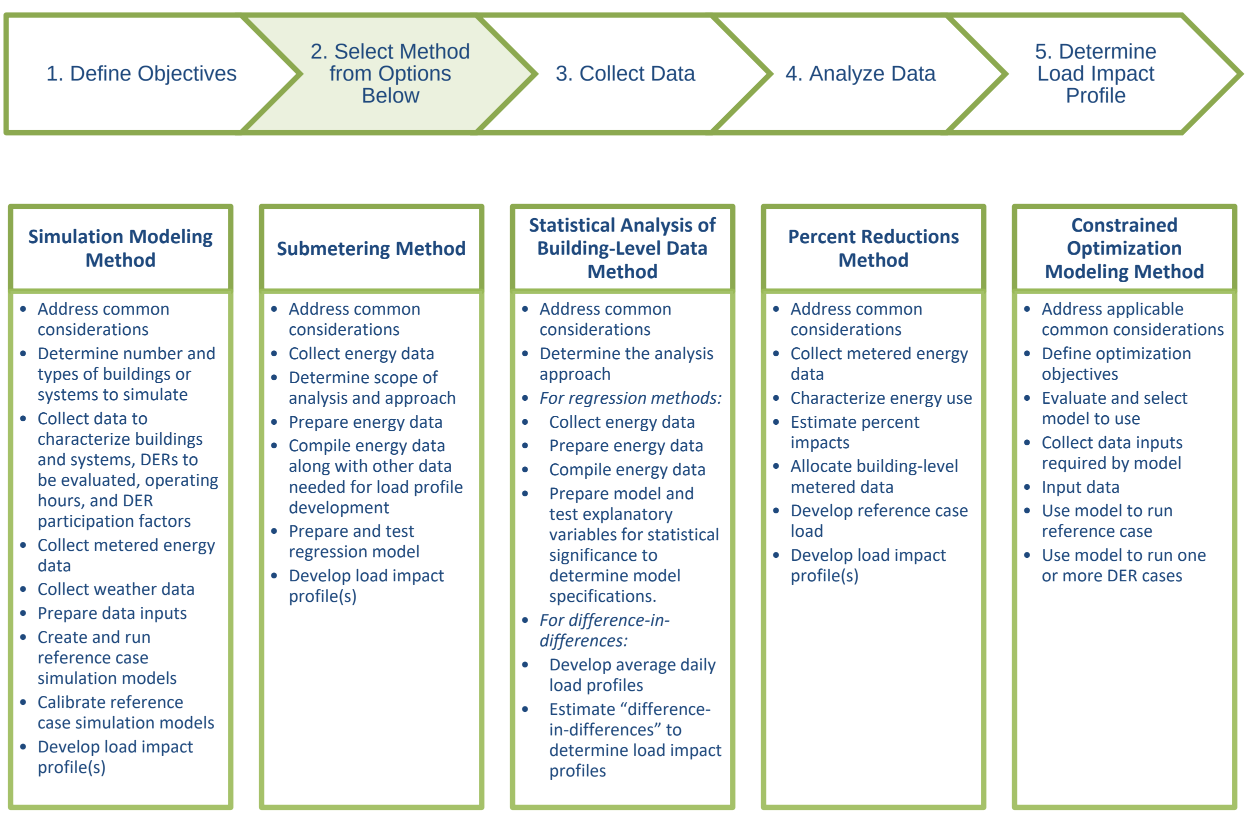


Table 84 summarizes key attributes of the methods as they pertain to developing DER load impact profiles. The sections below describe the methods and attributes in more detail.

Table 84. Summary of method attributes relevant to DER load profile development

Method	Attribute					
	Applicability to DER Types	Single- vs. Multiple-DER Approach	Relative Cost	Relative Analytic Complexity	Relative Accuracy	Captures Interactive Effects
Simulation Modeling	All	Multiple	Low-Med	Med-High	Med	Maybe
Submetering	All	Single	High	Med	High	No
Statistical Analysis of Building-Level Data	All	Multiple[30]	Med	Med-High	High	Yes
Percent Reductions	Some	Multiple	Low	Low	Low	Maybe
Constrained Optimization Modeling	Some	Multiple	Low-Med	Med-High	Med-High	Yes

While there have been some important advancements in application of these methods in recent years—due in part to technology advances and greater access to interval data—these basic methods for developing load profiles are not new.[31] Several are regularly applied by utilities in various aspects of load research and program planning. For example, utilities use simulation modeling (often relying on a consultant or public source) for energy efficiency end-use load profiles in assessing program cost-effectiveness. Utilities also frequently use statistical regression analysis in their load research to derive sample-weighted hourly load profiles for different rate classes in a cost of service study, and statistical regression analysis with class load research data is sometimes used for market settlement as well. Additionally, many utilities use statistically adjusted end-use forecasts as the basis for their load forecasts in IRPs. These methods are also commonly applied in program impact evaluation (EM&V). Load profiles derived as part of a past or current impact evaluation for a DER program or pilot are directly relevant to a BCA since those impacts help inform load forecasts and utility planning with respect to DERs.

11.2.2. Common Considerations

Despite inherent differences in the methods, there are several common considerations in developing DER load impact profiles. At the most basic level, a solid understanding of the types and characteristics of the DERs to be evaluated and the specific objectives of the BCA is essential. Another fundamental consideration is accounting for resource interactions when conducting multiple-DER analysis. In addition, timescales and metrics for the avoided costs and DER load impacts should ideally match. Any analysis should also address and quantify uncertainty to the extent practicable. These basic considerations are described more fully below:

[30] Can capture the combined impact of multiple DERs, but it is difficult to allocate impacts to individual DERs.

[31] A 1990 ACEEE publication refers to many of these same methods (see LBNL 1990).

- *DERs to be evaluated*: The types of DERs to be evaluated, customer classes of interest, and the objectives of the BCA are essential considerations in planning for and developing DER load impact profiles.
- *Resource interactions*: Interactions between different resources must be accounted for to estimate impacts accurately. Some methods can capture and isolate interactions better than others. Conceptually, accounting for resource interactions means that the Reference Case load profile is adjusted after each DER is analyzed. That way, as subsequent DERs are added to the analysis, their impacts will be calculated relative to the adjusted baseline. Factors to consider include "loading order" of the resources (defined as the order the DERs are added to the analysis, i.e., what happens first) and how the DERs are expected to interact (will they compete, complement each other, or have no effect on one another?). For example, see LBNL 2020 EE-DR for a conceptual framework to describe energy efficiency and demand response interactions.
- *Time interval*: Hourly intervals are generally the preferred choice when developing load profiles if the incremental cost information is available or can be estimated at that granularity. For some DER use cases, sub-hour intervals may be desirable if there are load impacts that are not evident in hourly intervals. In others, it might be sufficient to estimate average load impacts for key sub-annual periods, such as winter and summer or on- and off-peak periods.
- *Time stamp convention*: When working with multiple datasets containing interval data, it is important to make sure the data align. Considerations include whether the time stamp reflects the beginning or end of the interval and how daylight savings time is handled.
- *Time period*: The key time periods that reflect DER operation should be captured in the load profiles. The time periods may be specific hours, days, weeks, months, seasons, or years. Day-types—such as average weekday, average weekend day, monthly peak day, winter system peak day, and summer system peak day—are often used to represent time periods of interest.
- *Study period*: The BCA study period should be long enough to include the full operating life of the DER being analyzed. Therefore, DER load impact profiles and corresponding incremental costs ideally should be developed to represent each year during the life of the DERs being evaluated to capture any expected variations in load impacts and incremental costs across years. Variations in load impacts may be due to persistence factors (i.e., degradation of impacts over time) or increases in adoption of DERs. In multiple-DER analysis, combined impacts in later years may change due to different lifetimes for different types of DERs.
- *Load metric*: The load metric (kW, kWh, therm, etc.) must align with the avoided cost metric ($/kW, $/kWh, $/therm, etc.). With sub-hour interval data, it is also important to pay special attention when calculating kWh (an energy unit) based on kW (a power unit). For example, to convert 15-min kW data to 15-min kWh, multiply each kW measurement by ¼ hour. To convert 15-min kW data to hourly kWh, average the four 15-min kW measurements for each hour. To convert 15-min kWh data to hourly kWh, sum the four 15-min kWh values within each hour.
- *Uncertainty*: All estimation methods have uncertainty. Some types of errors are easier to quantify than others. Best practice is to identify and quantify (when possible) sources of errors and then report them by creating confidence intervals around point estimates.

Option 1: Simulation Modeling Method

Energy simulation modeling uses physics-based principles to estimate DER load impact profiles. Building energy simulation models use available primary or secondary data on building characteristics to simulate how buildings and sub-systems use energy. Very detailed models can be built up to represent specific buildings or, alternatively, building prototypes can be developed or obtained from open sources to represent different customer classes of interest. They can also be used to optimize building characteristics and DER measures (like energy efficiency, demand response, and electrification) to minimize costs. Other types of simulation models focus on estimating (and optimizing) impacts from distributed generation and distributed storage systems. Calibrated simulation models reconcile results from the physics-based models to actual metered energy data.

The simulation modeling method involves the key steps shown in Table 85.

Table 85. Steps to develop DER load profiles using simulation modeling

Step 1	Address the common considerations listed above
Step 2	Determine the number and types of buildings or systems to simulate If a sample of buildings will be analyzed to represent a larger population, determine the size of the population.
Step 3	Collect data to characterize the buildings and systems, DERs to be evaluated, operating hours, and DER participation factors Data to describe buildings and operation could come from actual sites, utility surveys that generalize characteristics by customer type (e.g., data collected during a baseline study), secondary sources, or a combination of sources. The data requirements will vary depending on the type of building, type of model, and level of customization required.
Step 4	When available, collect metered energy data (and energy cost information if doing financial analysis along with load impacts) The energy data could be in the form of monthly billing data, smart meter data, and/or submeter data from specific end-uses or DERs being evaluated. The type of energy data to use will depend on what is available. Usually, when choosing the simulation modeling approach to estimate building energy use, only whole-building energy data is available, and it may only be available at the monthly level; but it is possible to have more granular data, including from submeters. Another determining factor for the type of energy data to collect is whether the model is predicting impacts due to various DER scenarios or whether the model is estimating impacts after DER implementation. If the former, the collected energy data would be for the Reference Case period. If the latter, the collected energy data would be for the DER Case period as well as the Reference Case period, if available.
Step 5	Collect weather data The weather data should correspond with the timescales of the study. Simulations are often conducted at the hourly level to represent annual operation ("8760" models). The weather should also reflect the conditions of interest for the study (actual weather, normal weather, something else).
Step 6	Prepare the data inputs Conduct basic cleaning and validation of the energy data. Organize all data inputs to align with the appropriate simulations.
Step 7	Create and run the Reference Case simulation models Develop a Reference Case model for each building or system type. This could include developing a prototype or using or adapting a prototype or model from a secondary source. The output will include simulated energy loads at the building and subsystem level in hourly (or possibly sub-hourly) increments.
Step 8	Calibrate the Reference Case simulation models

	If available, use metered energy data from the Reference Case period to calibrate the model.[32] Examples of when appropriate Reference Case metered energy data may not be available include new construction, building expansions, changes in industrial processes, other non-routine events, or if consumption and sales are different because of onsite generation (this would be a problem if the model is designed to capture consumption and the metered energy data represents sales).
Step 9	Use the calibrated model to simulate DER Cases Run one or more DER Case simulations for each building or system type. This involves adapting the Reference Case model to reflect the DERs to be assessed. The DER Case should include all DERs under evaluation for the given scenario.
Step 10	Calibrate the DER Case simulation models (if DERs are already implemented) Use metered energy data from the DER period to calibrate the models for buildings that have already implemented DERs.
Step 11	Develop load impact profile(s) Calculate the DER load impact profile by subtracting the loads for the DER Case from the Reference Case for each interval and calculate for each building or system type and aggregate and expand to the populations of interest.

The following attributes characterize the simulation modeling method:

Applicability to DER Types: The simulation modeling method applies to all DER types.

Single- vs. multiple-DER approach: The simulation modeling approach can be used for single or multiple DERs, depending on the package of DERs being evaluated. For example, a distributed generation system would probably be modeled separately from energy efficiency measures, while a package of energy efficiency and electrification measures could be evaluated together in the same simulation model. There is a distinction because building energy simulation models developed with engines like EnergyPlus and DOE-2 simulate buildings and their systems and can be used to estimate the effects of various actions—including energy efficiency measures, electrification, and demand response strategies—on end-use systems, while other models like PVWatts simulate distributed generation systems for a given building or topography.

Cost and complexity: This method has a low-to-medium cost and medium-to-high complexity compared to other methods. Factors that influence the cost and complexity are the sophistication requirements for the models (how closely does the model need to match an actual building vs. a "typical" or average building), the sample size (how many buildings or systems need to be simulated), and the DERs to be evaluated (how many and what type of DER scenarios are needed). The lowest cost and simplest application of this measure is the use of free software with user-friendly interfaces to evaluate a small number of sites and for a limited set of DER scenarios. An example of this would be using PVWatts to estimate performance of solar PV (see Section 11.4.1). The highest cost and most complex application of this method is to create a large number of detailed building energy models using a building simulation engine such as EnergyPlus or DOE-2; that would require considerable expertise and time. Generally, creating a building energy model from scratch would not be required because there are several software

[32] When a sample of buildings is being simulated to represent a population of buildings, an additional calibration step can be performed. First, expand simulated loads for the sample to the population. Then make adjustments to reconcile the simulated values with the metered loads for the population.

interfaces available (including OpenStudio, eQUEST, and BEopt) to simplify use of simulations engines. In addition, developing prototypes to represent the average building for each customer class and building type of interest is easier than developing unique simulation models for each specific building. It is also possible to use prototypes from secondary sources, as long as there is the capability for customization where needed. See Section 11.5.2.a for descriptions of some publicly available building simulation models and tools.

Accuracy: In general, this method has medium accuracy compared to other methods. Models that calibrate to metered data are more accurate than those that do not. The accuracy also depends on the quality of the inputs used to characterize the buildings. There are often challenges collecting sufficiently detailed data on building characteristics to create an accurate model or prototype. One advantage of this method is that individual DER impacts can be readily isolated from building-level impacts. One disadvantage is that the models do not capture behavioral effects.

Interactive effects: The ability of simulation modeling to account for interactive effects depends on the model. Some building energy simulation models are able to account for interactive effects between some types of DERs. This attribute is very useful when looking at different combinations of DERs as well when assessing the effects of a DER on other end-uses, such as how building envelope measures affect the HVAC load. (See LBNL 2020 EE Buildings for an example of using simulation models to analyze interactions between energy efficiency and demand response on regional grid scales.)

Option 2: Submetering Method

Submetering uses measurements of energy or proxies of energy (current, voltage, power factor) to develop load profiles. In the simplest application of this method, the measurements are used directly without additional manipulation or adjustment. However, statistical approaches are often used to analyze the data and to correlate impacts to explanatory variables.

The submetering method involves the key steps described in Table 86.

Table 86. Steps to develop DER load profiles using the submetering method

<table>
<tr><td>Step 1</td><td>Address the common considerations listed above</td></tr>
<tr><td>Step 2</td><td>Collect the energy data

Key considerations include:
Data source: Submeters, building automation systems, data loggers, etc.
Data type: Energy consumption, distributed generation output, distributed storage, or electric vehicle charging/discharging measurements, other
Data scale: Sample size, population of customers (or systems) included in aggregate analysis
Data availability: Is submeter data available to represent both the Reference Case and DER Case, or just one or the other?</td></tr>
<tr><td>Step 3</td><td>Determine the scope of the analysis and approach

Key considerations include:
Type of load profile(s) to be developed: This will depend on the available submeter data and type of DER. For energy efficiency and demand response, if only Reference Case data is available (or only DER Case data is available), then an end-use load profile can be developed but the load impacts will need to be estimated with other methods, such as Simulation Modeling or Percent Reductions. However, if the submeter data reflects both Reference Case and DER Case loads, the DER load impact profile can be estimated as the</td></tr>
</table>

difference of the two. For other DERs like solar PV, battery storage, electric vehicles, and electrification, the DER load impact profile can be developed directly since the submeter would be recording actual operation of the DER instead of a change in operation of a given end-use.

- Analysis approach: In some cases, submeter data might be used directly without further manipulation to convey the load profiles for the measurement period. However, it is far more common to use statistical regression analysis to develop and analyze load profiles from sub-metered data; generally linear regressions are employed. Statistical regressions help quantify relationships between the load and one or more explanatory variables. If the right submeter data is available, regression models can include both Reference Case and DER Case variables so that DER impacts can be calculated from the model. These types of models allow users to estimate impacts under different conditions by varying values for the explanatory variables.

Step 4 Prepare the energy data

Conduct basic data cleaning and validation procedures and aggregate data to data intervals of interest. For example, if submeters record data at intervals of 5 mins and hourly profiles are desired, aggregate the data to hourly levels.

If the data is not going to be regressed, prepare a dataset for conveying load profiles for the time period and data interval of interest. If applicable, calculate load impacts by aligning Reference Case and DER Case data (by time of day, day of week, etc.) and computing the difference.

If using regressions, complete Steps 5-7.

Step 5 Compile the energy data along with other data needed for load profile development

This includes data such as weather data, calendar data, customer data, other variables.

Step 6 Prepare and test the regression model

This involves testing explanatory variables for statistical significance and determining the best model specification.

Step 7 Develop load impact profile(s)

Apply the model to estimate the Reference Case, DER Case, and/or DER load impact profiles, as applicable. Typically impacts are estimated at an average customer level for a given customer class and then reconciled to the population of interest. The impacts should capture the study period and conditions relevant for the BCA (e.g., time, day, season, weather). The choice of weather applied in the model—actual weather, normal weather, event day weather, or something else—should be consistent with the type of DER being analyzed and should correspond to incremental cost data.

The following attributes characterize the submetering method:

Applicability to DER Types: The submetering method potentially applies to all DER types but is not the best choice for behavioral-based or strategy-based DER analysis. For example, submetering a solar PV system alone cannot discern whether or not the customer consumed more energy after installing solar PV as a result of now having lower energy bills; in other words, it cannot capture rebound effects. Additionally, though submetering can readily capture how a customer charged their electric vehicle under a particular rate, a more rigorous experimental study design leveraging submetering would be required to assess how different rates would yield different charging profiles.

Single- vs. multiple-DER approach: Submetering is inherently a single-DER analysis approach, however, it can be used for multiple-DER analysis if all DERs and end-uses known to be affected by DERs are sub-metered.

Cost and complexity: This method has a high cost and medium complexity compared to other methods. The simplest and least-cost application of the method is for DER impacts that can be measured directly, such as for solar PV systems, batteries, electric vehicles, and electrification. It is also applicable to energy efficiency and demand response measures; but the expense, complexity and, in some cases, the time commitment is greater since loads should ideally be measured for the Reference Case and DER Case to calculate the load impact profile.

Accuracy: The accuracy of submetering is high relative to other methods since it involves direct temporal load measurements of DERs or end-uses known to be affected by DERs.

Interactive effects: Submetering cannot account for interactive or fuel-switching effects unless all other systems expected to be affected by the DER are also sub-metered.

Option 3: Statistical Analysis of Building-Level Data Method

This method uses statistical approaches to model Reference Case and DER Case loads and determine load impacts from building-level interval energy data. Typically, the data is from utility smart meters that record load data in sub-hourly or hourly intervals.

Statistical analysis of building-level data involves the key steps in Table 87.

Table 87. Steps to develop DER load profiles using statistical analysis of building-level data

Step 1	Address the common considerations listed above
Step 2	Determine the analysis approach Examples of statistical approaches for analyzing building-level interval data include difference-in-differences, fixed effects regression, and customer-specific regression:[33, 34, 35] • Difference-in-differences: This method is applied when comparing a control group to a treatment group. The control group's energy use serves as the Reference Case, while the treatment group's energy use informs the DER Case. Customers in the treatment group have been participants in a DER program. In this method, interval data is collected during the pre-treatment period and treatment period for both the control group and the treatment group. • Fixed effects regression: As noted earlier, regression models help quantify relationships between the load and one or more explanatory variables like weather, customer type, and time-related variables. Fixed effects regressions can be used to analyze a Reference Case and a DER Case for a group of customers that have participated in a DER program, or to compare a control group with a treatment group. In either application, interval data is collected during the pre-treatment period and treatment period for all customers in the sample. • Customer specific regression: This method is useful when analyzing impacts for customers that have very different load profiles from one another. The regression models are developed for each customer participating in the program and then the results are aggregated into customer groups of interest. For example, this method works well for estimating load impact profiles for commercial

[33] See AEG 2017 for an example of using both the difference-in-differences approach and the fixed effects regression approach to estimate load impacts for SmartMeter-enabled informational energy efficiency programs.

[34] See LBNL 2021 Hourly Savings for an example of using regression analysis to estimate hourly load impacts from residential space conditioning measures.

[35] See AEG 2018 for an example of using customer-specific regression analysis to estimate hourly load impacts for aggregator-based demand response programs.

	and industrial customers participating in aggregator-managed demand response programs. In that application, the DER Case is an event day and the Reference Case is a non-event day.

For the regression methods, the remaining steps (Steps 3a-7a) are essentially the same as Steps 3-7 in the *Submetering method*.

Step 3a	Collect the energy data
Step 4a	Prepare the energy data
Step 5a	Compile the energy data
Step 6a	Prepare the model and test explanatory variables for statistical significance to determine the best model specifications
Step 7a	Develop load and load impact profiles from the models for the conditions of interest

For difference-in-differences, the remaining steps are as follows:[36]	
Step 3b	**Develop average daily load profiles** Develop profiles for each customer in the control group and treatment group, for each day type of interest and for both the pre-treatment period and the treatment period. For the customer segments of interest, average the daily load profiles across the customers to get average per-customer load profiles for each segment. The result will be average Reference Case (control group) load profiles and average DER Case (treatment group) load profiles for each customer segment and day type.
Step 4b	**Estimate the "difference-in-differences" to determine the load impact profiles** • Estimate the first difference. For each customer segment and each day type, calculate the difference between the control group's average load and the participant group's average load. Calculate for both the pre-treatment and treatment periods. • Estimate the second difference. Subtract the first difference for the pre-treatment period from the first difference for the treatment period to get an estimate of the load impacts that corrects for pre-treatment differences between the control group and treatment group. Calculate for each customer segment and day type of interest. Aggregate the impacts to the population.

A variation to the methods described above is *Normalized Metered Energy Consumption (NMEC)*. The NMEC approach is emerging as part of the next generation measurement and verification concept ("Advanced M&V" or "M&V 2.0"). This approach entails using building-level (or subsystem level) interval data along with automated modeling processes—often employing statistical regressions—to assess overall load impacts for the building (or subsystem). The key differentiator from the other regression approaches already discussed is the analysis is done in "real time" to provide fast feedback on the performance of DERs. This fast feedback helps building operators understand and manage energy use more dynamically and allows for more accurate and timely estimates for pay-for-performance programs. Advanced M&V leveraging the NMEC approach also shows potential as an enabling method for assessing the performance of *grid-interactive efficient buildings* at the fine timescales and high speeds required for grid services. These same qualities of fine timescales and high speed are well suited for assessing temporal impacts at the building or subsystem level from non-wires solutions. However, advanced M&V and its application to grid-interactive efficient buildings and *non-wires solutions* is still in the early stages.[37]

The following attributes characterize the statistical analysis of building-level data method:

Applicability to DER Types: The statistical analysis of building-level data method applies to all DER types.

Single- vs. multiple-DER approach: This is a multiple-DER analysis approach since impacts are calculated at the building level. However, it is difficult to attribute impacts to individual DERs without more complex models or submetering.

Cost and complexity: This general method category has a medium-to-high cost and high complexity compared to other methods. Of the statistical approaches, the simplest and least cost is the difference-in-differences method. It is the easiest to apply since it is based on direct comparisons of loads for the

[36] Additional steps may be required to create a matched control group if the control group has not already been defined.

[37] See SEE Action 2020 for more information issues and considerations related to assessing impacts from grid-interactive efficient buildings. See RMI 2018 NWS for more information on implementing non-wires solutions.

Reference Case and DER Case. Fixed effects regression is more complex (and therefore more costly) than difference-in-differences because of the need to develop a regression model, but it is less complex and less costly than customer-specific regressions since the latter requires developing and testing models applicable to multiple customer types. The NMEC method is the most complex and costly since it involves very sophisticated models and may require paying for a software service.

Accuracy: The accuracy of this method is relatively high (at least at the building level) since the loads are based on actual interval meter data for both the Reference Case and the DER Case. This method has the advantage over other methods in that it captures behavioral effects.

Interactive effects: Whole-building statistical approaches inherently capture interactive effects of measures for a given energy source (usually electricity). However, they cannot account for fuel-switching effects unless the other affected fuels are also analyzed.

Option 4: Percent Reductions Method

This method applies estimates of percent reductions in DER load impacts (e.g., energy savings or peak demand reductions) to Reference Case load profiles to develop DER load impact profiles. The Reference Case load profiles may be obtained from public sources or developed with one of the other methods described above.

The percent reductions method involves the key steps in Table 88.

Table 88. Steps to develop DER load profiles using the percent reductions method

Step 1	Address the common considerations listed above
Step 2	Collect metered energy data This includes annual and monthly utility data, and any hourly or sub-hourly interval data that is available at the whole-building or submeter level for customers included in the analysis scope.
Step 3	Characterize energy use Use primary or secondary sources to characterize the buildings and subsystems (including end-uses and technologies) for each customer class and building type of interest. Data could come from actual sites, utility surveys that generalize characteristics by customer type (e.g., data collected during a baseline study), secondary sources (e.g., U.S. EIA), or a combination of sources. Identify any customers with onsite generation, such as those with solar PV who participate in net-metering programs.
Step 4	Estimate percent impacts Use engineering calculations, models, measurements, or secondary sources to estimate the percent impacts from the DERs for the time periods relevant to the use case. For example, specific day types and specific hours of the day may be relevant for a demand response use case, while it may be sufficient to estimate impacts at the seasonal or annual level for an energy efficiency use case. In some use cases the percent impact may represent an overall building-level impact (e.g., for a behavioral program), but often the percent impact would be calculated at the end-use level (e.g., installing efficient lighting or HVAC equipment).

Step 5 Allocate building-level metered data

This will result in an estimate of average per-customer energy use for each customer class and building type. It involves the following sub-steps:

- Compile metered data for all customers within a given customer class and building type.
- Calculate the average annual (or more granular) energy use per customer (or sq ft) for each customer class and building type.
- When conducting end-use level analysis, allocate the average energy use to end-uses and technologies using the customer characterization data.

Step 6 Develop Reference Case load

This step is carried out for all customer classes and building types and involves two sub-steps:

- Using load profiles obtained from primary or secondary sources (see Section 11.5.1), compile a set of unitized load profiles, preferably at the end-use and technology level, to represent each customer class and building type of interest. In a unitized load profile, the sum of the values for the period (usually increments of 8760 hours per year) equals 1.0. Therefore, the value for each increment is a small fraction. These fractional values can be multiplied by a total load for the period (usually an annual load) to develop a load profile.
- Multiply the unitized load profiles by the average customer energy use at the building level (or at the end-use and technology level). The calculation will involve multiplying each fraction in the unitized load profile by the energy use value for the period (e.g., annual kWh/customer or annual kWh/sq ft).

Step 7 Develop load impact profile(s)

Apply the estimated percent impacts to the Reference Case load profiles. There are a few ways to do this depending on the use case:

- For building-level estimation, apply percent impacts to the building-level Reference Case profile to develop a load impact profile. This method assumes that the impact profile will have the same shape as the Reference Case profile, but with a lower magnitude.
- For end-use or technology level estimation, apply percent impacts to the corresponding end-use or technology level Reference Case profile to develop separate load impact profiles for each end-use or technology. These can then be stacked to determine the combined impact at the building level.
- When conducting this analysis for specific intervals—such as to assess the impact of demand response during the system peak hours—the percent impacts would only be applied to those intervals.

The following attributes characterize the percent reductions method:

Applicability to DER Types: The percent reductions method is most appropriate for energy efficiency and certain types of demand response (specifically load shed) when the timing of the load impacts is known or can be readily estimated from Reference Case load profiles.

Single- vs. multiple-DER approach: This is a multiple-DER approach. Separate percent reductions for individual DERs are estimated separately. Then, they are stacked to create a combined load impact profile. When stacking the DER impacts, it is important to account for resource interactions; this involves adjusting the Reference Case load between each additional DER so that the overall impacts are not overstated. (See Section 11.4.2 for an example of using percent reductions for multiple-DER analysis.)

Accounting for Resource Interactions: As a simple example, consider a Reference Case load of 100 kW that is reduced by 10% to 90 kW by the first DER, resulting in a 10 kW impact. The second DER has a percent reduction of 5%. If applied to the original load of 100 kW, the load impact of the second DER would be 5 kW; however, it would be 4.5 kW if applied to the adjusted 90 kW reference load. If resource interactions were not accounted for, the impact would be 10 kW + 5 kW = 15 kW, which is overstated. To account for resource interactions, the appropriate stacked impact should be 10 kW + 4.5 kW = 14.5 kW.

Cost and complexity: This method has a low cost and low complexity relative to the other methods.

Accuracy: The accuracy is relatively low since temporal load impacts are not measured or simulated; instead, the method's underlying assumption is that the DER load impact profile has the same general shape as the Reference Case profile during the time period under evaluation, but loads are adjusted upwards or downwards. Nevertheless, this method works very well as a planning tool for energy efficiency and demand response resources.

Interactive effects: It is possible to account for interactive effects using the percent reductions method if the interactive effects are known and can be estimated. For example, efficient lighting measures affect HVAC loads. So, to account for the interactive effects, both the percent reduction in the lighting load and the percent changes (increase or decrease) in the HVAC loads would need to be calculated.

Option 5: Constrained Optimization Modeling Method

Constrained optimization modeling is a special class of simulation models designed to make it easier to compare and optimize different DER scenarios for a given site (or other topography) to meet specific objectives (minimizing costs, maximizing resiliency, minimizing greenhouse gas emissions, etc.). This type of modeling is particularly useful for DERs that can be more flexible and responsive to fluctuating grid needs, such as distributed storage.

There are several tools available to the public for evaluating DER options; some are free, and some are not. Section 11.5.2.b summarizes a few constrained optimization modeling tools, including Homer Energy's HOMER Grid and HOMER Pro, NREL's System Advisory Model (SAM) and REopt Lite, LBNL's DER-CAM, and Sandia National Laboratories' QuESt. (See Nguyen 2021 for a comparison of these and other models.) The sophistication and capabilities vary across the models. A common feature is that each model requires user input of parameters such as location, energy costs, energy loads, and information to describe the site and DERs of interest. Some models are equipped with libraries of load profiles to select from when setting up the model and will also pull in other data (solar, wind, weather data) from secondary sources. In addition, some models output very granular time series data on how the DERs serve the building loads, including hourly performance profiles. Others report optimized cost and performance metrics that can be used along with load profiles from within the model or from other sources to estimate DER load impact profiles.

Table 89 shows the basics steps for using an existing modeling tool to optimize DER alternatives.

Table 89. Steps for optimizing DER alternatives using an existing modeling tool

Step 1	Address the applicable common considerations listed above
Step 2	Define optimization objectives Variable(s) to be minimized or maximized and the constraints.
Step 3	Evaluate and select a model to use

	See Section 11.5.2.b for a few options.
Step 4	Collect data inputs required by the model These will likely include information to define the site, loads, location, weather, energy prices, existing DERs, and DERs to be evaluated.
Step 5	Input data Models may have a combination of custom inputs and drop-down menus or libraries from which to select.
Step 6	Use the model to run Reference Case The output will reflect the loads and costs without the DERs to be evaluated.
Step 7	Use the model to run one or more DER cases For each DER Case, the output will reflect the loads and costs for an optimized scenario.

The following attributes characterize the constrained optimization modeling method:

Applicability to DER Types: These types of models are designed to optimize a range of DER options to meet different objectives. However, in the context of evaluating DERs for a BCA, constrained optimization modeling is most applicable to dispatchable DERs that can provide grid services, i.e., distributed storage, electric vehicles (vehicle-to-grid), distributed generation plus storage and/or electric vehicles, and use of these technologies for demand response.

Single- vs. multiple-DER approach: This is primarily a multiple-DER analysis approach since different combinations of DERs can be simulated and optimized. (See Section 11.4.3 for an example of constrained optimization modeling of solar PV and storage.)

Cost and complexity: The cost of this method is low-to-medium, and the complexity is medium-to-high relative to the other methods. The cost will depend on whether the model is free or requires a license. The complexity will depend on how much and what type of data is required, how many sites and scenarios will be modeled, and the model's user interface.

Accuracy: The accuracy of the model and model output are a function of the sophistication of the model, the underlying algorithms and assumptions used in the model design, and the quality of the inputs. Relative to the other methods, the accuracy would be in the medium-to-high range if the inputs represent the use case reasonably well.

Interactive effects: This method accounts for interactive effects when the models are used to optimize combinations of DERs.

11.2.3. Load Profile Considerations for Fossil Fuels

Some types of DERs reduce fossil fuels consumed by the customer. Examples include energy efficiency through natural gas measures, interactive effects from electric energy efficiency measures, and electrification (fuel switching). Electrification may be for building end-uses such as heat pumps for HVAC or water heating, for transportation (electric vehicles), and even for distributed generation and storage such as solar PV and batteries displacing fossil fuel generators. The fossil fuels may be in the form of natural gas, propane, oil, gasoline, or diesel.

A BCA analysis will *only* require load profiles for fossil fuels to the extent that incremental cost information is available at the temporal level. Temporal data for fossil fuel loads and costs are generally less available and often less granular than temporal data for electric loads and costs. When data is available, the load impacts should ideally be analyzed with the same time interval as the incremental fuel cost data. Load profiles for affected fossil fuels should be developed to correspond to the time periods they would have been operating in the absence of the given DERs. This may or may not correspond to the DER load impact profiles.

Many of the methods described in this chapter apply to fossil fuel analysis—*when and if* there is an important temporal relationship with incremental cost. Applicability of the methods is particularly true for fuels, like natural gas, that are supplied to buildings and metered, or for fossil fuel-fired equipment that can be sub-metered. In those cases, simulation modeling, submetering, statistical approaches, and percent reductions are all good options. Granular load profile analysis for fuels used in transportation is not likely to be applicable in a BCA.

11.3. Applying Methods to Different Types of DERs

There are various factors to consider when applying methods to develop load impact profiles for different types of DERs. Specifically, some methods are more applicable to certain DERs than others. In addition, each type of DER has a unique set of characteristics that must be taken into account when developing load impact profiles. This section explains these factors.

11.3.1. Mapping of Methods to DER Types

The method attributes discussion in Section 11.2 described the general applicability of each method to specific types of DERs. Table 90 summarizes this mapping of methods to DER Types. Presence of a check mark indicates the method is applicable to the given DER type.

Table 90. Mapping of methods for developing load profiles to DER types

Method	DER Type					
	Energy Efficiency	Electrification	Distributed Generation	Distributed Storage	Electric Vehicles	Demand Response
Simulation Modeling	✓	✓	✓	✓	✓	✓
Submetering	✓	✓	✓	✓	✓	✓
Statistical Analysis of Building-Level Data	✓	✓	✓	✓	✓	✓
Percent Reductions	✓					✓
Constrained Optimization Modeling			✓	✓	✓	✓

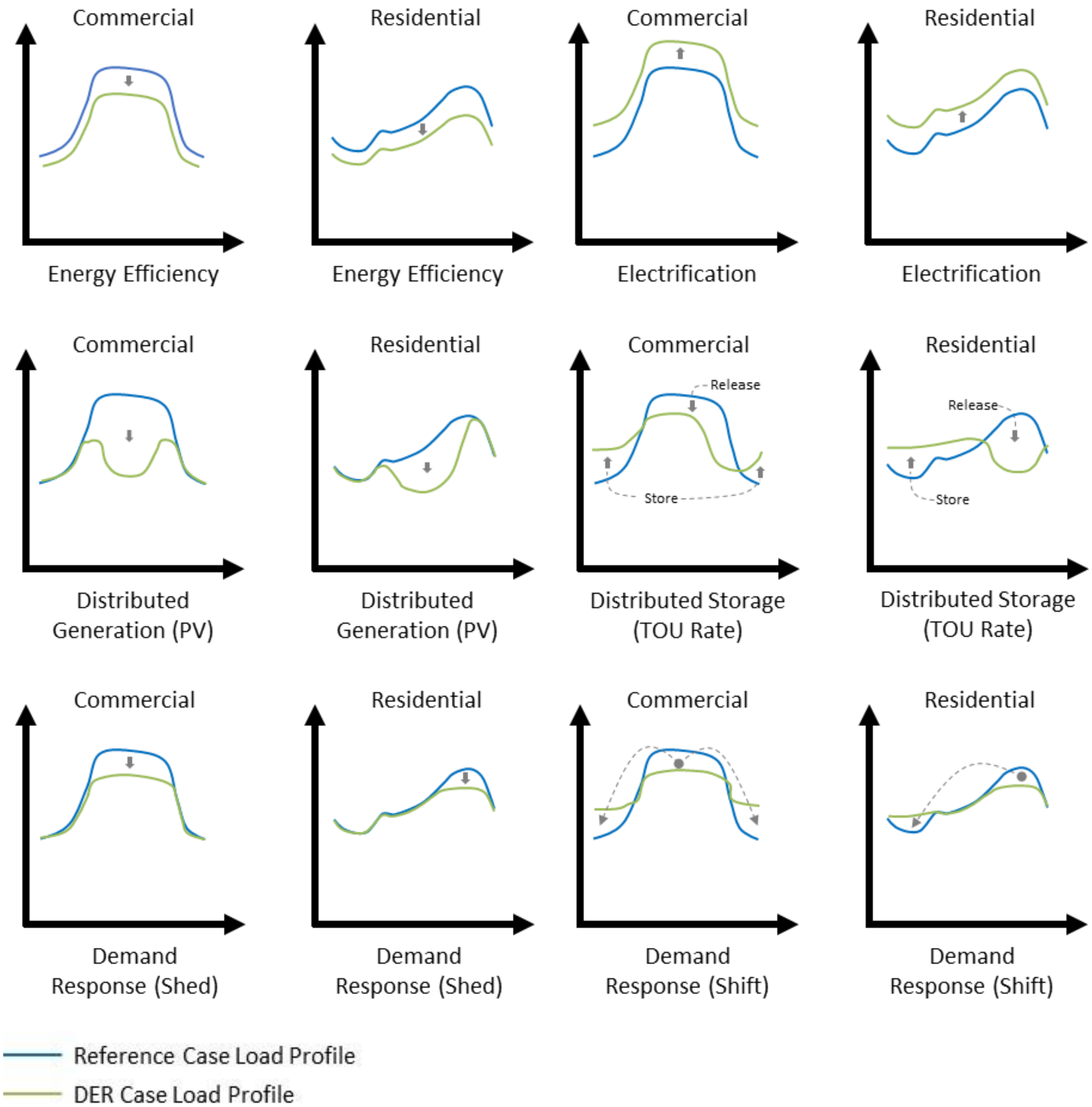
Note: Constrained optimization modeling of distributed generation applies especially in the context of distributed generation plus distributed storage and/or electric vehicles.

In some ways, specific characteristics of the DERs and their load profiles make a given method appropriate. For example, the percent reductions method is really only applicable to traditional energy efficiency and certain types of demand response (e.g., load shed) because those types of DERs yield load reductions during predictable hours of the day. The relevant hours correspond to when the end-use equipment operates (energy efficiency) or during known peak periods (demand response). In contrast, constrained optimization models apply for DERs that can be more flexible, like distributed storage and electric vehicles, as well as for when demand response is used as a more flexible resource (i.e., through use of grid-integrated end-use equipment and controls). The following subsections discuss characteristics associated with DERs and their load profiles in more detail.

11.3.2. Key Characteristics of Load Profiles by DER Type

Different types of DERs have different effects on Reference Case load profiles. Whether those effects increase or decrease loads, are persistent or temporary, are controllable or not, and are more evenly or less evenly distributed across the profile depend on the type of DER. Figure 47 on the next page presents a set of graphics showing examples of how the different types of DERs can affect load profiles. The graphs compare Reference Case and DER Case profiles for hypothetical commercial and residential buildings. These are simplified examples. Actual load profiles will depend on the specific use cases and could look very different than these.

Figure 47. Illustrative load profiles for DERs in commercial and residential buildings



The subsections below describe characteristics of load and load impact profiles for three groupings of DERs: (1) more passive resources (energy efficiency and electrification); (2) more active resources (distributed storage, electric vehicles, and demand response); and then (3) distributed generation, which could be active or passive depending on the use case. The descriptions include a discussion of key factors to consider when developing load impact profiles.

11.3.3. Energy Efficiency and Electrification

Traditional energy efficiency and electrification measures can be thought of as passive resources that either decrease (energy efficiency) or increase (electrification) loads relative to a reference case. The timing of those reductions or increases in loads correspond to when the affected end-uses consume energy. For example, efficient lighting will yield a greater reduction in residential loads during the evening, efficient air conditioning will yield greater reductions during summer afternoons and switching from a gas furnace to a heat pump increases loads more during winter nights. Thus, there are important temporal aspects to these load changes, but they tend to be well correlated with weather, seasons, daylight, and building operation. The benefit of this passive attribute is that the load impacts are more reliable, and their timing is more predictable. In addition, once the load impact profiles are well characterized for one jurisdiction, they are more readily adaptable to another that has a similar climate and market, which greatly simplifies development of load impact profiles for a BCA. From a grid services perspective, a downside of this passive attribute is there is less flexibility to alter the load profiles to meet grid objectives.

A new class of resources is emerging that is more active and therefore more dispatchable. A few examples include smart thermostats, smart appliances, grid-integrated water heaters, and electric vehicles. These resources can be thought of as energy efficiency measures—or electrification for the case of electric vehicles—but their controllability features allow them to be used for other grid services, such as for addressing localized or system-wide capacity constraints. Therefore, they integrate features of energy efficiency and demand response and are sometimes referred to as integrated DSM (iDSM) resources. Load impact profiles for iDSM will vary based on things like how much flexibility they offer, how they are controlled, and when they are needed by the grid, which means that developing load impact profiles requires consideration of different use cases.

The subsections below list some specific aspects to consider when developing load impact profiles for traditional energy efficiency and electrification resources.

11.3.3.a. Energy Efficiency

Key considerations for developing load impact profiles for energy efficiency resources include approaches for:

- Determining savings (i.e., engineering algorithms, benchmarking studies, direct measurements, or whole-building statistical approaches),
- Disaggregating building-level loads to end-use level when using whole-building approaches, and
- Spreading impacts across a representative load profile when only monthly or annual savings have been determined. A common assumption for energy efficiency is that the load impact profile has the same shape as the load profile but depending on the measure or portfolio of measures this may or may not be the case.

The first four methods in Section 11.2 apply to energy efficiency resources: simulation modeling, submetering, statistical analysis of building-level data, and percent reductions.

11.3.3.b. Electrification

Key considerations for developing load impact profiles for electrification include:

- Determining how the electric technologies change the end-use load shapes (e.g., for HVAC and water heating). Unlike for energy efficiency measures, electrification always creates a new or very different load profile than the Reference Case of a fossil fuel-fired end-use. Therefore, the load impact profile will have a different shape than the Reference Case.
- Differentiating between unmanaged and managed electrification loads. For example, load impact profiles from unmanaged electric storage water heaters and electric vehicles should be analyzed differently than managed electric storage water heaters and electric vehicles. (See Section 11.3.4 for a discussion of managed loads.)

- Understanding fuel-switching implications and when it will be necessary to develop a fossil fuel load profile (see Section 11.2.3 for more information).

The first three methods in Section 11.2 apply to electrification resources: simulation modeling, submetering, and statistical analysis of building-level data.

11.3.4. Distributed Storage, Electric Vehicles, and Demand Response

The attribute that distributed storage, electric vehicles, and demand response all have in common is they are (or have the potential to be) active resources. They can be managed by the customer or directly by the utility to respond to a price signal or to a reliability or resiliency event. Their load impact profiles will vary depending on the use case. General considerations related to developing load impact profiles include the following:

- The reliability and accuracy of the estimated load impact profile depend on if and how the resource(s) is controlled. For example, direct control leads to greater reliability and less uncertainty than a time-of-use rate, which is designed to influence customer behavior.
- Optimizing how and when the resource is used to meet priorities. This is where the constrained optimization method comes in, to evaluate various scenarios and their load impact profiles.
- Whether bulk power or distribution system values are needed. Distribution system analysis is more complicated and less accurate.

In addition to the general considerations, the subsections below list some specific aspects to consider when developing load impact profiles for each of these three types of resources.

11.3.4.a. Distributed Storage

For distributed storage, key considerations include:

- The type of storage (electro-chemical, thermal energy, electro-mechanical, other),
- Source of storage (dedicated battery storage systems, electric vehicle batteries, thermal energy storage from ice banks, thermal energy storage from water heater storage tanks, etc.),
- Methods to account for operational patterns (i.e., how patterns vary for different use cases, including effects of rates on temporal impacts), and
- How well and completely the storage is utilized to meet objectives.

If reduction in GHG emissions is a priority, another consideration that affects the load impact profile of a distributed storage system is the “roundtrip efficiency.” Because of losses, more energy is used to charge a battery than is available during discharge. The analogous is true for a thermal energy storage system. Therefore, when minimizing GHG emissions, care should be taken to optimize operation such that the storage release portion of the cycle avoids more GHG emissions than caused during the storage portion of the cycle.

Four of the methods described in Section 11.2 are applicable to distributed storage: simulation modeling, submetering, statistical analysis of building-level data, and constrained optimization modeling. The best method to use when trying to optimize operation of storage resources is the constrained optimization method.

11.3.4.b. Electric Vehicles

Key considerations for electric vehicles include:

- Whether the vehicle will be used in a managed charging program (e.g., shifting charging to off-peak periods), a vehicle-to-grid application where the grid will draw power from electric vehicle batteries when needed, or if it is just being analyzed as an unmanaged new electric load (electrification),
- Roundtrip efficiency when the vehicle's battery is used as an active storage resource,
- Methods to account for the effects of time-of-use rates,
- Multiple charging locations (home, work, other),
- Variability of charging patterns for different customers and different use cases,
- Type of vehicle (light-, medium-, or heavy-duty),
- Vehicle-miles traveled, and
- Location.

As with distributed storage, four methods described in Section 11.2 are applicable to electric vehicles: simulation modeling, submetering, statistical analysis of building-level data, and constrained optimization modeling. See EPRI 2018 for an example of using submetering with data loggers to conduct load profile analysis of electric vehicles. For a review of publicly available electric vehicle load data and models, see Amara-Ouali 2021.

> Distributed storage and electric vehicles are two potential ways to enable the load shift type of demand response. In both cases, the energy can be stored during off-peak or non-event periods and then released when needed to meet demand response objectives. If there is charge and discharge, roundtrip efficiency should be considered.

11.3.4.c. Demand Response

Key considerations for demand response include:

- The demand response mode (e.g., load shed, shift, or modulation) because the fundamental shape of the load impact profile will vary depending on mode,
- The type of demand response program and type of control (direct load control, automated demand response, manual switching, other),
- Granularity of the time interval needed, and
- Methods for determining the Reference Case.

Incentive-based programs (like direct load control, interruptible/curtailable demand response, and market-based demand response) and price-based programs (like time-of-use rates and critical peak pricing) will require different types of methods to estimate impacts and corresponding load impact profiles. For example, incentive-based programs may use similar non-event days to model the Reference Case for each participant, while price-based programs may use control groups to estimate impacts for groups of participants.

All of the methods in Section 11.2 apply to demand response, but the choice of the method will depend on the use case.

11.3.5. Distributed Generation

Load impact profiles for distributed generation are the same as distributed generation profiles, except to the extent they change customer behavior and except for any line losses that might occur between generation and use.[38] Because of this difference relative to other types of DERs, distributed generation load impact profiles are generally the easiest to develop using measurements of output and publicly available simulations models.

The first three methods in Section 11.2—simulation modeling, submetering, and statistical analysis of building-level data—apply to distributed generation resources. The constrained optimization method also applies, but only to the extent that the output from the distributed generation resource can be controlled to address grid needs. Generation technologies like solar PV and wind are not fully controllable resources in the sense that they only generate electricity when the renewable resource is available. However, they are often modeled in combination with other DERs (specifically storage) to determine an optimal scenario.

Key considerations for developing distributed generation load impact profiles include:

- The types of generation (solar PV, wind, combined heat and power, other),
- Whether the generation technology displaces an on-site fossil-fueled alternative (like a diesel generator),
- Effects of weather and other operating conditions on output,
- How behavioral effects influence impacts, and
- Operating assumptions of the distributed generation resources that are assumed or incorporated within an aggregate resource profile (including interactions with storage or other DERs).

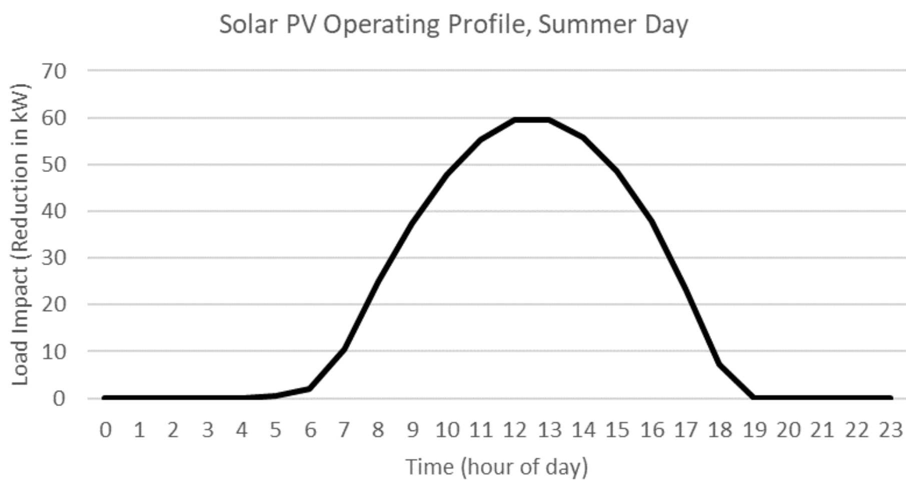
11.4. Illustrative Examples

11.4.1. Simulation Modeling of Solar PV

Figure 48 shows output from NREL's PVWatts simulation tool. The tool was used to model a solar PV system for an apartment complex at a senior living facility in California. The analysis is part of a larger plan to explore the cost-effectiveness of implementing energy efficiency measures, electrification, electric vehicles, solar PV, and batteries at the facility and other affiliated sites across the country with a goal of reaching net zero GHG emissions at these sites by 2040. Figure 48 shows the simulated AC system output for a typical summer day. The output represents the solar PV system's estimated load impact profile, which is an estimate of the DER load impact profile. This example illustrates a use case where the DER load impacts can be estimated directly, without needing to develop Reference Case and DER Case load profiles first. See Section 11.5.2.a for a description of the PVWatts tool.

[38] Line losses for distributed generation are likely to be inconsequential.

Figure 48. Illustrative example – single DER analysis: simulation of solar PV output for an apartment complex



Source: Smith 2021. Used with permission.

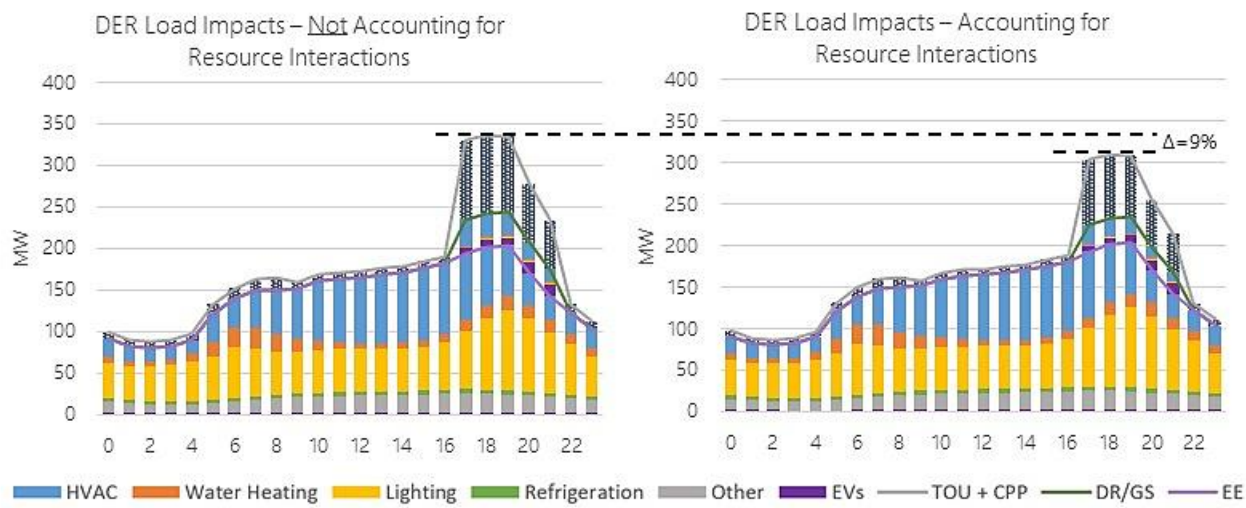
11.4.2. Percent Reductions, Building Simulation Models, and End-Use Load Profiles for Multiple-DER Analysis

Figure 49 shows examples of load impact profiles from a market potential study conducted in 2020 for the State of Hawaii (see AEG 2020). Hawaiian Electric is currently using results from the study to inform its integrated grid planning process. Several scenarios were modeled during the study. The load impacts in Figure 49 represent an "achievable-high" potential scenario, which means cost-effectiveness and likely customer adoption are accounted for in the potential. The profiles reflect hourly load reduction impacts on a critical peak day due to:

- Energy efficiency (EE),
- Demand response / grid services (DR/GS) – for a load shed scenario that includes impacts from electric vehicles (EVs) and other end uses, and
- A time-of-use plus critical peak pricing (TOU+CPP) rate.

The potential was calculated for the year 2030 and includes combined impacts for the residential and commercial sectors.

Figure 49. Illustrative example – multiple-DER analysis: comparison of DER load impact profiles with and without accounting for resource interactions



Note: DERs include energy efficiency, demand response (load shed), and TOU+CPP rate. Critical peak day, Oahu, all sectors, 2030. Source: AEG 2020. Used with permission.

The analysis was conducted two ways to depict the effect of resource interactions. First, the DERs were analyzed in isolation to develop impacts that did not account for resource interactions (graph on left in Figure 49). Then, the analysis was revised to account for interactions between the different types of DERs (graph on right in Figure 49). To account for resource interactions, energy efficiency impacts relative to the Reference Case were modeled first. Next, the time-of-use rate was modeled assuming the energy efficiency measures had been implemented.[39] Last, the demand response impacts were modeled assuming both the energy efficiency measures and rate were in place. Comparing the two figures shows that the maximum hourly impact was 336 MW (6 pm) for the figure on the left, compared with 309 MW (6 pm) for the figure on the right; this illustrates the point that the load impacts would have been overstated (by about 9 percent for that particular hour) if the resource interactions were not accounted for.

The impacts in Figure 49 were modeled using a combination of the following:

- AEG's Load Management Analysis and Planning (LoadMAP™) model
- The Brattle Group's PRISM model
- Building simulation models using Hawaii's normal weather data for weather-sensitive loads:
    - Single-family residential prototypes developed in BEopt™ with EnergyPlus v8.8 as the simulation engine using Hawaii-specific data on housing characteristics and end uses. See Section 11.5.2.a for a description of these simulation models.

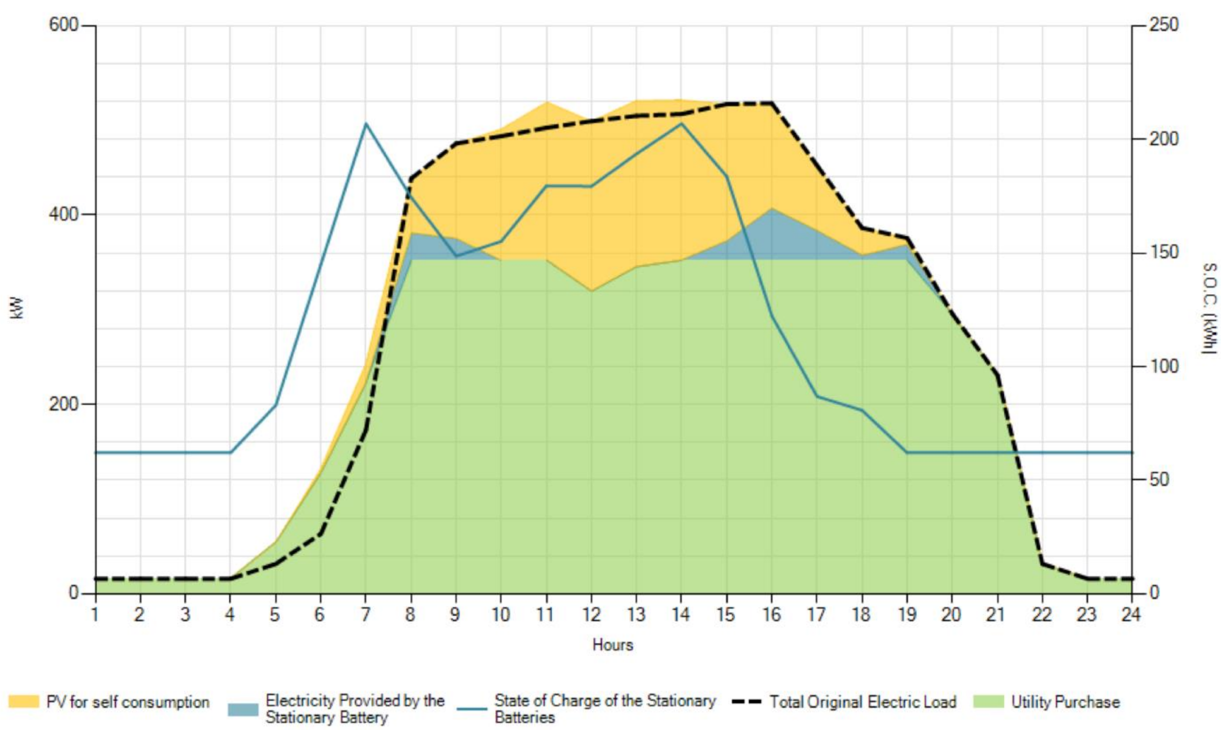
[39] For visual clarity, impacts for the rate appear on the top of the load impact profile with the black and white cross pattern and the gray line, even though the rate was second in the loading order.

- Other building simulations from the NREL's OpenEI dataset using models developed for IECC Zone 1A, Hawaii's climate zone. See Section 11.5.1 for a description of NREL's simulated hourly load profiles.
- End-use load profiles from the California Energy Commission (CEC) for non-weather sensitive measures. See Section 11.5.1 for a description of the CEC's electricity load profiles.
- The *percent reductions* approach was used to cast estimates of annual energy efficiency impacts to 8760 hourly end-use profiles.

11.4.3. Constrained Optimization Modeling of Solar PV and Storage

Figure 50 shows an example of results from LBNL's DER-CAM optimization modeling tool. The tool was used to analyze investment in solar PV and battery storage for a large office building in San Francisco. The model optimized dispatch of the DERs to reduce the customer's energy costs against a retail tariff with monthly demand charges. The graph in Figure 50 includes the Reference Case load profile (black dashed line labeled "Total Original Electric Load"), the DER Case load profile (green area labeled "Utility Purchase"), PV used by the customer (yellow-orange area), electricity provided by the stationary battery (blue area), and state of charge (S.O.C) of the battery (blue line plotted using axis on right side of graph). The graph depicts electricity dispatch for a peak day in May. Inputs for this model included site data, end-use load data for different day types, utility tariffs and export options, DER options and associated parameters, and optimization objectives and constraints. For more information about this example, see LBNL 2018 DER-CAM.

Figure 50. Illustrative example – constrained optimization modeling using DER-CAM



Note: Portrayal of investment in solar PV and battery storage to minimize energy costs for large office building in San Francisco, CA. Source: Grid Integration Group, LBNL 2018 DER-CAM Used with permission.

11.5. Resources for Developing DER Load Profiles

There is a growing library of publicly available tools and resources for developing load and load impact profiles. There are also myriad models and tools that are not public. Figure 51 below provides examples of useful tools and resources in the public domain, with descriptions summarized from information provided on the websites. The major advantages of using existing tools and resources are that they are much simpler, faster, and less expensive to apply. End-use load profile libraries provide load profiles for a wide variety of end-uses, building types, and locations. Some modeling tools for distributed generation and distributed storage allow sensitivity analysis and the ability to readily explore various scenarios without the need for an extensive metering study or pilot program to estimate impacts. Possible concerns with using a tool or resources from a secondary source are the reliability of the underlying information, and the degree to which it is applicable to other services territories with climatic and other regional differences. While some tools and resources allow user input or selection of customized inputs like weather and cost data, others are more limited in their customization features. A key disadvantage of relying solely on public tools and resources is the limited availability of load *impact* profiles at the end-use level for some types of DER measures and scenarios. However, it is important to note that recent and planned efforts by the national laboratories and others have been mitigating some of these issues.

Figure 51. Examples of publicly available tools and resources for developing load and load impact profiles

End-Use Load Profiles

- End-Use Load Profiles for the U.S. Building Stock, NREL, LBNL, Argonne National Laboratory, 2021
- End Use Load Profile Inventory, LBNL, 2019
- California Investor-Owned Utility Electricity Load Shapes, California Energy Commission, 2019
- Commercial and Residential Hourly Load Profiles for all TMY3 Locations in the United States, NREL, 2014
- Load Shape Library, EPRI, version 8.0

Simulation Models

- Building Energy Modeling, DOE
- eQUEST, James J. Hirsch & Associates, Version 3.65
- BEopt™, NREL, Version 2.8.0.0,
- PVWatts® Calculator, NREL, version 6.2.4

Optimization Models

- SAM: System Advisory Model, NREL, version 2020.2.29
- REopt™ Lite, NREL, version Feb 2021
- DER-CAM, LBNL
- QuESt, Sandia National Laboratories
- Storage Value Estimation Tool (StorageVET® 2.1), EPRI
- DER Value Estimation Tool (DER-VET™), EPRI
- HOMER Grid and HOMER Pro, Homer Energy

Normalized Metered Energy Consumption

- OpenEEmeter, Recurve and LF Energy

Impact Estimation References

- CalTRACK, Working Group under Energy Market Methods Consortium (EM2)
- IPMVP, Efficiency Valuation Organization
- Uniform Methods Project, DOE Office of Energy Efficiency & Renewable Energy

11.5.1. End-Use Load Profiles

- **End-Use Load Profiles for the U.S. Building Stock**, NREL, LBNL, Argonne National Laboratory, 2021 (www.nrel.gov/buildings/end-use-load-profiles.html) – Database of end-use load profiles representing all major end uses, building types, and climate regions in the U.S. commercial and residential building stock. Developed with simulation models calibrated and validated with empirical datasets. The output of each building energy model is 1 year of energy consumption in 15-minute intervals, separated into end-use categories. The dataset has also been formatted to be accessible in three ways—via pre-aggregated load profiles in downloadable spreadsheets, a web viewer, and a detailed format that can be queried with big data tools—to meet the needs of many different users and use cases.

- **End Use Load Profile Inventory,** LBNL, 2019 **(**www.emp.lbl.gov/publications/end-use-load-profile-inventory) – An Excel file that lists datasets that contain hourly load profiles and are publicly available. The inventory includes load profile data from submetering, master metering, and plug loads. Metadata about each data source is recorded, in an effort to aid researchers looking for existing load profile studies and wishing to filter by attributes such as location, customer sector, or end-use category.
- **California Investor-Owned Utility Electricity Load Shapes**, California Energy Commission, 2019 (www.energy.ca.gov/publications/2019/california-investor-owned-utility-electricity-load-shapes) – This project updated traditional end-use load shapes for six energy sectors and developed photovoltaic system, light-duty electric vehicle, and energy efficiency load impact profiles, which will be used as inputs for the Demand Analysis Office's California Energy Demand Forecast. The California Energy Commission currently uses the Hourly Electric Load Model to cast annual energy demand forecast elements into hourly demands, from which projected annual peak loads are forecasted. The Hourly Electric Load Model includes weather-sensitive and weather-insensitive load shapes at the end-use, planning area, and forecast zone level for the residential and commercial sectors, and at the whole-building level for other sectors. The project updated end-use load shapes by blending publicly available load shapes from market and metering studies with building simulations in a framework known as EnergyPlus. The project relied on aggregated interval meter data provided by electric investor-owned utilities to calibrate energy simulations and to develop models for other sectors. The load shapes and profiles developed under this project are dynamic entities within "load shape generators," which can respond to relevant factors such as calendar data, weather data, macroeconomic data, and in some cases, price signals from utility time of use rates.
- **Commercial and Residential Hourly Load Profiles for all TMY3 Locations in the United States**, NREL, 2014 (www.data.openei.org/submissions/153) – Hourly end-use load profile data for 16 commercial building types and residential buildings in all TMY3 locations in the United States. The commercial load data is based on the Commercial Reference Buildings (www.energy.gov/eere/buildings/commercial-reference-buildings) and the residential load is based on the Building America House Simulation Protocols (www.nrel.gov/docs/fy11osti/49246.pdf).
- **Load Shape Library,** EPRI, version 8.0 (www.loadshape.epri.com/) – Intended to demonstrate basic features of Load Shape Profiling. Website has interactive interface to view hourly end-use load shapes by sector and whole premise load shapes by building type and sector. There are also some hourly and daily load shapes for certain residential measures by location, day type, and technology type.

11.5.2. Models

11.5.2.a. Simulation Models

- **Building Energy Modeling**, DOE (www.energy.gov/eere/buildings/about-building-energy-modeling) – Through the Building Technologies Office (BTO), DOE develops and maintains two software packages for building energy modeling: EnergyPlus™ (version 9.3.0) and OpenStudio™. EnergyPlus is an open-source whole-building energy modeling engine; it is the successor to the DOE-2 (version 2.1E) simulation engine developed by LBNL. OpenStudio is a software development kit that reduces the effort of EnergyPlus-based application development. BTO distributes EnergyPlus and OpenStudio under a commercial-friendly non-exclusive open-source license.
- **eQUEST,** James J. Hirsch & Associates, Version 3.65, (www.doe2.com/equest/) – The QUick Energy Simulation Tool (eQuest) is a free user-interface that combines schematic and design development building creation wizards, an energy efficiency measure wizard and a graphical results display module with the DOE-2 (version 2.2) building energy use simulation program.
- **BEopt™,** NREL, Version 2.8.0.0, (www.nrel.gov/buildings/beopt.html) – The BEopt (Building Energy Optimization Tool) software is free. It provides capabilities to evaluate residential building designs and identify cost-optimal efficiency packages at various levels of whole-house energy savings along the path to zero net energy. It can be used to analyze both new construction and existing home retrofits, as well as single-family detached and multi-family buildings, through evaluation of single building designs, parametric sweeps, and cost-based optimizations. It provides detailed simulation-based analysis based on specific house characteristics, such as size, architecture, occupancy, vintage, location, and utility rates. Discrete envelope and equipment options, reflecting realistic construction materials and practices, are evaluated. BEopt uses the EnergyPlus simulation engine.
- **PVWatts® Calculator**, NREL, version 6.2.4 (www.pvwatts.nrel.gov/) – PVWatts is a free, basic solar modeling tool that estimates energy production and costs of grid-connected PV systems. It calculates hourly or monthly PV energy production based on minimal inputs and can be used to develop generation profiles. An online interactive interface utilizes the PVWatts calculator.

11.5.2.b. Optimization Models

- **SAM: System Advisory Model**, NREL, version 2020.2.29 (www.sam.nrel.gov/) – SAM is a free tool that models techno-economic performance and cost predictions of renewable energy systems, including distributed PV, battery storage, wind power, and other types of distributed renewable energy systems.
- **REopt™ Lite**, NREL, version Feb 2021 (www.reopt.nrel.gov/tool) – REopt Lite is a free web-based tool for evaluating the economic viability of distributed PV, wind, battery storage, combined heat and power, thermal energy storage, and geothermal heat pumps (GHP) at an existing site. It identifies system sizes and dispatch strategies to minimize energy costs. It also estimates how long a system can sustain critical load during a grid outage.
- **DER-CAM**, LBNL (www.gridintegration.lbl.gov/der-cam) – The Distributed Energy Resources Customer Adoption Model (DER-CAM) is a free decision support tool that can be used to find the optimal portfolio, sizing, placement, and dispatch of a wide range of DERs in the context of either buildings or multi-energy microgrids, while co-optimizing multiple stacked value streams that include load shifting, peak shaving, power export agreements, or participation in ancillary

service markets. While the objective function of DER-CAM can be easily modified — or even replaced by a multi-objective analysis — it is most commonly defined as a site's total annual cost of energy supply. This includes costs associated with both new and existing DER, operation and maintenance costs, fuel costs, and also all costs related to utility imports either fixed, time-dependent, energy-based, or power-based. Additionally, all value streams associated with the optimal DER dispatch determined by DER-CAM are considered in the objective function, both in the form of avoided costs and market participation. The model requires hourly end-use profiles as inputs and provides outputs of when and how the DER should optimally be dispatched. See LBNL 2018 DER-CAM for steps to complete a DER-CAM analysis.

- **QuESt,** Sandia National Laboratories (www.sandia.gov/ess-ssl/tools/quest/) - QuESt is a free, open source, application suite for energy storage simulation and analysis. It currently consists of three applications that help project users evaluate energy storage systems for different use cases. QuESt Data Manager helps manage the acquisition of ISO market data, US utility rate data, commercial and residential load profiles, and essential data for use in other QuESt applications. Given an energy storage device, an electricity market with a certain payment structure, and market data, QuESt Valuation estimates the maximum revenue from participating in energy arbitrage or providing ancillary services. QuESt BTM estimates cost savings from behind-the-meter energy storage for time-of-use and net energy metering customers. A PV power profile can be included to co-locate with a building and energy storage. It uses a location-specific commercial and residential building load profile from secondary open sources to represent demand and provides monthly estimates of cost savings.
- **Storage Value Estimation Tool (StorageVET® 2.1)**, EPRI (www.storagevet.com) – StorageVET 2.1 is a free, web-hosted, energy storage value simulation tool. It facilitates the understanding of where to place and install energy storage, the optimum size as well as controls options. It implements dispatch optimization with sensitivity analysis to assist in planning energy storage project development by enabling rapid analysis of scenarios with different storage sizes, costs, and value streams. Additionally, StorageVET 2.1 is valuable as a research tool to inform broad-sweeping analyses of trends in storage value as a function of location, operation, and technical capabilities.
- **DER Value Estimation Tool (DER-VET™)**, EPRI (www.der-vet.com) – DER-VET is a free, open-source, optimization-based energy valuation and planning tool for DERs and larger, centralized energy resources. It was developed by expanding on the framework developed in EPRI's Storage Value Estimation Tool (StorageVET). It supports site-specific assessments of energy storage and additional DER technologies—including solar, wind, demand response, electric vehicle charging, internal combustion engines, and combined heat and power—in different configurations, such as microgrids. It uses load and other data to determine optimal size, duration, and other characteristics for maximizing benefits based on site conditions and the value that can be extracted from targeted use cases.
- **HOMER Grid and HOMER Pro**, Homer Energy (www.homerenergy.com/) – HOMER Grid combines engineering and economics to rapidly perform complex calculations for comparing design outcomes and considering options for minimizing project risk and reducing energy expenditures. It allows for any combination of components (electric vehicle charging, battery, solar, wind, generator, grid, combined heat and power) and outputs the total energy cost for each possible system. The optimization features allow for maximizing savings, minimizing cost, increasing resilience, optimizing electric vehicle charging stations, reducing carbon emissions, stacking values to increase return on investment, and exploring combined heat and power.

HOMER Pro simulates the operation of a hybrid microgrid for an entire year, in time-steps from one minute to one hour. It looks at all possible combinations of equipment and presents options that can be selected to create an optimal system. Both of these models provide tools to help the user select and customize load profiles. The outputs from HOMER Pro include hourly time series plots for viewing the generation from each component, how it serves the load, the resources that power the components, as well as a number of key operational characteristics from each component for an entire year of your simulation. There is also a "profile" option that shows the hourly performance for an average day for each month for the selected parameter.

11.5.2.c. Normalized Metered Energy Consumption

- **OpenEEmeter**, Recurve and LF Energy (www.lfenergy.org/projects/openeemeter/) – An open source toolkit for implementing and developing standard methods for calculating normalized metered energy consumption (NMEC) and avoided energy use. The OpenEEmeter library contains routines for estimating energy efficiency savings at the meter. OpenEEmeter includes the reference implementation of the CalTRACK methods (see below) for estimating normalized metered energy savings. OpenEEmeter, as implemented in the eemeter package and its companion eeweather package, contains the most complete open source implementation of the CalTRACK methods, which specify a family of ways to calculate and aggregate estimates of avoided energy use at a single meter particularly suitable for use in pay-for-performance programs. The model does not directly generate load profiles, but can be used with reference case and DER case load data to generate profiles.

11.5.3. Impact Estimation Resources

- **CalTRACK**, Working Group under Energy Market Methods Consortium (EM2) (www.caltrack.org/) – CalTRACK specifies a set of empirically tested methods to standardize the way normalized meter-based changes in energy consumption are measured and reported. When CalTRACK is implemented through open source software, these methods can be used to support procurement of energy efficiency, electrification, and other DERs.
- **IPMVP**, Efficiency Valuation Organization (www.evo-world.org/en/products-services-mainmenu-en/protocols/ipmvp) – The International Performance Measurement and Verification Protocol (IPMVP) provides methods, with different levels of cost and accuracy, for determining savings either for the whole facility or for individual energy conservation measures.
- **Uniform Methods Project**, DOE Office of Energy Efficiency & Renewable Energy (www.energy.gov/eere/about-us/ump-home) – Under the Uniform Methods Project, DOE is developing a set of protocols for determining savings from energy efficiency measures and programs. The protocols provide a straightforward method for evaluating gross energy savings for residential, commercial, and industrial measures commonly offered in ratepayer-funded programs in the United States. The measure protocols are based on a particular International Performance Verification and Measurement Protocol (IPMVP) option but provide a more detailed approach to implementing that option.

11.5.4. Resources for Developing DER Load Profiles

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12. COMPLETE LIST OF RESOURCES USED IN THIS HANDBOOK

Each chapter and many sections above include all the resources (i.e., documents, websites, and tools) that are *relevant to that chapter or section*. This chapter presents a complete list of all the resources that are referred to anywhere in this MTR handbook.

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