National Standard Practice Manual

For Benefit-Cost Analysis of Distributed Energy Resources

AUGUST 2020

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Acknowledgements

This *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM or the manual) is a publication of the National Energy Screening Project (NESP). The NESP is represented by a stakeholder group of organizations and individuals working to update and improve cost-effectiveness screening practices for distributed energy resources.

This manual incorporates and expands upon the guidance from the 2017 *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*, which presented the NSPM Framework, fundamental benefit-cost analysis principles, and guidance specific to energy efficiency resources.

The NESP is coordinated by E4TheFuture. Funding for the development of this NSPM was made possible by E4TheFuture with support from the US Department of Energy's Weatherization and Intergovernmental Programs Office under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or The Regents of the University of California.

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

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NSPM SUMMARY

The purpose of this *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM, or the manual) is to help guide the development of jurisdictions' cost-effectiveness test(s) for conducting benefit-cost analyses (BCAs) of distributed energy resources (DERs). BCAs involve a systematic approach for assessing the cost-effectiveness of investments by consistently and comprehensively comparing the benefits and costs of individual or multiple types of DERs with each other and with alternative energy resources.

This manual includes information for conducting BCAs of single and multiple types of DERs and provides use case examples that illustrate BCAs under different combinations and applications of DERs. The DER types covered in this manual are: energy efficiency (EE); demand response (DR); distributed generation (DG); distributed storage (DS); electric vehicles (EV); and increased electrification of buildings including heating and cooling systems.

Distributed Energy Resources (DERs) are resources located on the distribution system that are generally sited close to or at customers' facilities. DERs include EE, DR, DG, DS, EVs, and increased electrification of buildings. DERs can either be on the host customer side of the utility interconnection point (i.e., behind the meter) or on the utility side (i.e., in front of the meter). DERs are mostly associated with the electricity system and can provide all or some of host customers' immediate power needs and/or support the utility system by reducing demand and/or providing supply to meet energy, capacity, or ancillary services (time and locational) needs of the electric grid.

DERs represent a critical component of the evolution of the electricity grid by allowing for a more flexible grid, enabling two-way flows of energy, enabling third parties to introduce and sell new electricity products and services, and empowering customers to optimize their end-uses and consumption patterns to lower their bills and utility costs.

This manual is built around a BCA framework (the NSPM BCA Framework) that defines the steps a jurisdiction can use to develop its primary cost-effectiveness test—the Jurisdiction-Specific Test (JST). The framework also provides guidance on how consider and develop secondary tests, where applicable. The NSPM BCA Framework includes a set of core principles that are the foundation for developing and applying cost-effectiveness tests for BCAs.

The NSPM is policy-neutral in that it does not recommend any specific cost-effectiveness tests or policies, but rather supports BCA practices that align with a jurisdiction's policy goals and objectives. The manual thus serves as an objective, technology-neutral and economically sound guidance document for regulators, utilities, consumer advocates, DER proponents, state energy offices, and other stakeholders interested in comprehensively assessing the impacts of DER investments.

This manual incorporates and expands upon the guidance from the 2017 *NSPM for Assessing Cost-Effectiveness of Energy Efficiency Resources* (NSPM for EE). Both documents are products of the National Energy Screening Project (NESP), a multi-year effort guided by an advisory group represented by a range of experts with varying perspectives involved in BCA of DERs.

This NSPM provides objective, policy- and technology-neutral, and economically sound guidance for developing jurisdiction-specific approaches to benefit-cost analyses of distributed energy resources.

Terminology and Applicability of the NSPM

This manual uses many terms that are commonly used within the electricity and gas industries. Key terms are defined in a Glossary and in relevant sections of the manual. Some of the terms used in the manual are more broadly defined than in other applications, as noted below.

NSPM Terminology

Jurisdiction refers broadly to any region or service territory that would be served by the DERs being analyzed. This includes a state, a province, a utility service territory, a city or a town, or some other jurisdiction covered by regulators or other entities that oversee DER initiatives.

Utility refers broadly to any entity that funds, implements, or supports DERs using customer or public funds that are overseen by regulators or other decision-makers. This includes investor-owned utilities; publicly owned utilities (e.g., municipal or cooperative utilities); program administrators; community choice aggregators; regional transmission organizations and independent system operators; federal, state, and local governments; and others. *Utility expenditures* refers to spending by any of these entities on DERs.

Regulator refers broadly to any entity that oversees and guides DER analyses. This includes legislators and their staff; public utility commissions and their staff; boards overseeing public power authorities, municipal or cooperative utilities, or regional grid operators; and federal, state, and local governments.

Host customer refers to any customer that has a DER installed and/or operated on their site. In some cases, these are program participants (such as in a DR or EE program) while in other cases there is no program (such as with EV owners).

Third parties refer to the broad range of independent providers such as aggregators or implementation, service, or technology providers.

The principles and concepts presented in this manual are relevant to:

1. DER programs, procurements, or pricing mechanisms associated with expenditures on behalf of the public or utility customers, whether by utilities or others. For simplicity, these are referred to these as ‘utility expenditures.’
2. Any jurisdiction where DERs are funded, acquired, or otherwise supported by electric or gas utilities or others on behalf of their customers.
3. All types of electric and gas utilities, including investor-owned and publicly owned utilities (e.g., municipal or cooperative utilities.)
4. All types of utilities, including utilities that are vertically integrated, transmission and distribution (T&D), or distribution-only utilities, or those serving as a distribution platform for host customers to access a variety of energy services and DERs from third parties (e.g., aggregators).
5. Single DER and multiple DER BCA analyses, where:
    - *Single-DER analyses* involve assessing *one DER type* in isolation from other DER types, relative to a static set of alternative resources.
    - *Multiple-DER analyses* involve assessing more than one DER type at the same time relative to a *static or dynamic* set of alternative resources. Multiple-DER analyses covered in this manual include multiple *on-site* DERs, non-wires solutions within a specific *geographic area*, and *system-wide* DER portfolios.

- *Dynamic system planning* involves assessing multiple DER types relative to a dynamic set of alternative resources. Under this approach, the goal is to optimize both DERs and alternative utility-scale resources as well. This practice is relatively nascent and still evolving.

While the NSPM addresses BCA for single and multi-DER scenarios, it does not address every nuance or application for DER investments.

Manual Contents

The NSPM includes five parts:

- Part I presents the NSPM BCA Framework, including fundamental principles and guidance on the development of primary and any secondary cost-effectiveness tests.
- Part II describes the full range of potentially relevant DER benefits and costs (i.e., impacts), and presents several cross-cutting considerations on how to account for certain impacts.
- Part III provides guidance on single-DER BCA for various types of DER technologies. These chapters provide guidance on key factors and challenges that affect the impacts of each DER type.
- Part IV provides guidance on multiple-DER analysis. It addresses the three main ways that multiple-DER analysis is conducted: for a customer site; for a geographic region; and for an entire utility service territory. Part IV also addresses, at a high level, dynamic system planning.
- Appendices provide further detail on topics that warrant additional explanation. The appendices also provide information and templates on reporting BCA results.

Part I: The NSPM BCA Framework

Part I presents the NSPM BCA Framework, comprising three elements:

1. A set of **fundamental principles** that serve as the foundation for assessing the cost-effectiveness of potential DER investments in an economically sound and policy-neutral manner;
2. A **multi-step process** for developing or informing a jurisdiction's primary test—the Jurisdiction-Specific Test (JST)—as guided by the NSPM principles; and
3. Guidance on **when and how to use secondary tests** to inform (a) the prioritization of cost-effective DERs, as determined by a primary JST, and (b) decisions around marginally non-cost-effective DERs.

The **NSPM principles** in and of themselves do not determine a jurisdiction's appropriate cost-effectiveness test for DERs. The NSPM principles are intended to be applied in a manner that takes into consideration the characteristics and circumstances of each jurisdiction's approach to energy resources and can result in different JSTs for different jurisdictions.

Fundamental BCA Principles

The NSPM provides a set of fundamental BCA principles that represent sound economic and regulatory practices. The NSPM BCA principles presented in Table S-1 set the foundation for developing cost-effectiveness tests for BCA. The principles can be used to guide the application of cost-effectiveness testing, selection of a discount rate, and the reporting of the BCA results, and they can inform the process for prioritizing DERs to be implemented.

The NSPM BCA principles are not mutually exclusive as they contain some overlapping concepts. Further, there may be situations where it is necessary for jurisdictions to make tradeoffs between certain principles depending on specific situations.

Table S-1. NSPM BCA Principles

Principle 1	**Treat DERs as a Utility System Resource** DERs are one of many energy resources that can be deployed to meet utility/power system needs. DERs should therefore be compared with other energy resources, including other DERs, using consistent methods and assumptions to avoid bias across resource investment decisions.
Principle 2	**Align with Policy Goals** Jurisdictions invest in or support energy resources to meet a variety of goals and objectives. The primary cost-effectiveness test should therefore reflect this intent by accounting for the jurisdiction's applicable policy goals and objectives.
Principle 3	**Ensure Symmetry** Asymmetrical treatment of benefits and costs associated with a resource can lead to a biased assessment of the resource. To avoid such bias, benefits and costs should be treated symmetrically for any given type of impact.
Principle 4	**Account for Relevant, Material Impacts** Cost-effectiveness tests should include all relevant (according to applicable policy goals), material impacts including those that are difficult to quantify or monetize.
Principle 5	**Conduct Forward-Looking, Long-term, Incremental Analyses** Cost-effectiveness analyses should be forward-looking, long-term, and incremental to what would have occurred absent the DER. This helps ensure that the resource in question is properly compared with alternatives.
Principle 6	**Avoid Double-Counting Impacts** Cost-effectiveness analyses present a risk of double-counting benefits and/or costs. All impacts should therefore be clearly defined and valued to avoid double-counting.
Principle 7	**Ensure Transparency** Transparency helps to ensure engagement and trust in the BCA process and decisions. BCA practices should therefore be transparent, where all relevant assumptions, methodologies, and results are clearly documented and available for stakeholder review and input.
Principle 8	**Conduct BCAs Separately from Rate Impact Analyses** Cost-effectiveness analyses answer fundamentally different questions than rate impact analyses, and therefore should be conducted separately from rate impact analyses.

Process for Developing a Primary Jurisdiction-Specific Test

The primary test answers the critical question: Which DERs have benefits that exceed costs and therefore merit utility acquisition or support on behalf of customers?

The NSPM presents a step-by-step process for developing a primary cost-effectiveness test (or modifying an existing primary test). Referred to as the 'JST', this test reflects the fundamental BCA principles in Table S-1.

This manual presents the regulatory perspective, which refers to the perspective of regulators or similar entities that oversee utility DER investment decisions. A JST should reflect the regulatory perspective to ensure proper accounting of the jurisdiction's applicable policy goals—as guided by statutes, regulations, organizational policies, utility resource planning principles and policies, and/or other codified forms under which utilities or energy providers operate.

Figure S-1 illustrates the regulatory perspective relative to traditional cost-effectiveness test perspectives.

Figure S-1. The Regulatory Perspective

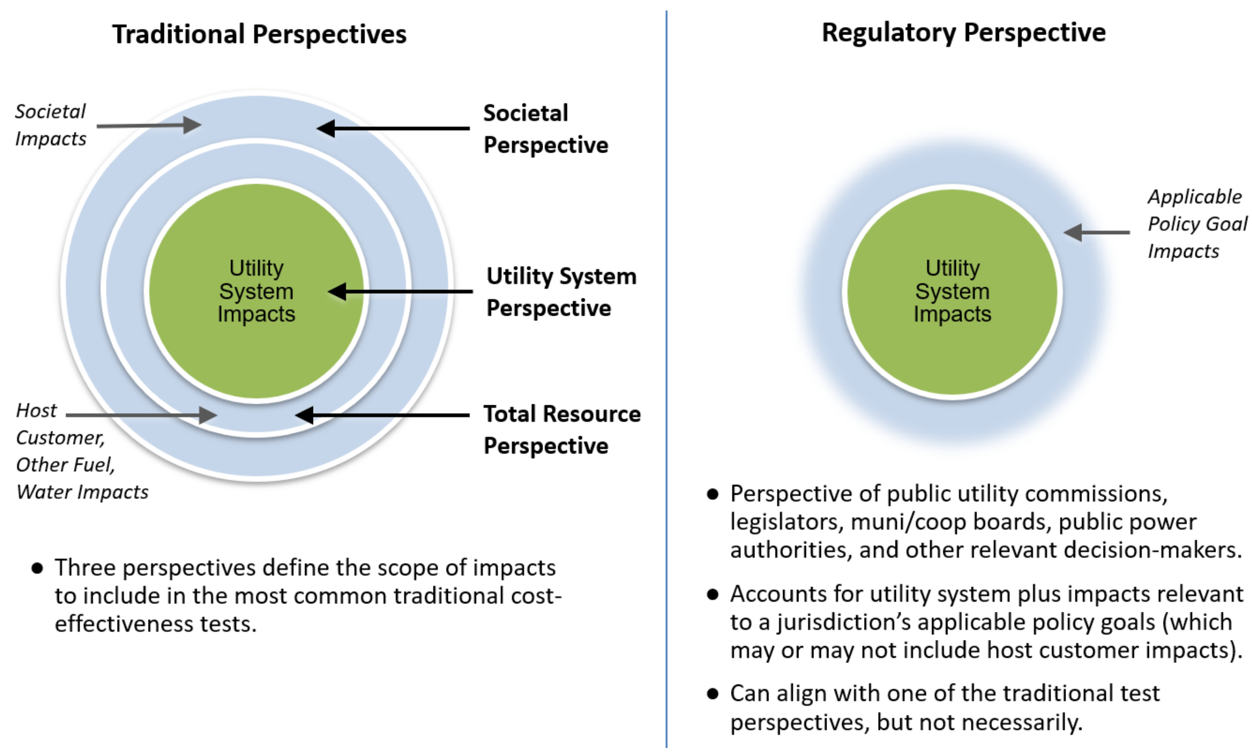


Table S-2 presents the multi-step process for developing a JST. This process provides the flexibility for each jurisdiction to tailor its primary JST to its own goals and objectives.

Table S-2. Developing a Jurisdiction's Primary Test: A 5-Step Process

STEP 1 Articulate Applicable Policy Goals

Articulate the jurisdiction's applicable policy goals related to DERs.

STEP 2 Include All Utility System Impacts

Identify and include the full range of utility system impacts in the primary test, and all BCA tests.

STEP 3 Decide Which Non-Utility System Impacts to Include

Identify those non-utility system impacts to include in the primary test based on applicable policy goals identified in Step 1:

- Determine whether to include host customer impacts, low-income impacts, other fuel and water impacts, and/or societal impacts.

STEP 4 Ensure that Benefits and Costs are Properly Addressed

Ensure that the impacts identified in Steps 2 and 3 are properly addressed, where:

- Benefits and costs are treated symmetrically.
- Relevant and material impacts are included, even if hard to quantify.
- Benefits and costs are not double-counted.
- Benefits and costs are treated consistently across DER types.

STEP 5 Establish Comprehensive, Transparent Documentation

Establish comprehensive, transparent documentation and reporting, whereby:

- The process used to determine the primary test is fully documented.
- Reporting requirements and/or use of templates for presenting assumptions and results are developed.

When deciding whether to include a benefit or cost in a BCA test, it is important to distinguish between the *definition* versus *application* of the BCA test. Any impact that is deemed to be relevant should be included as part of the definition of the test. In some cases, a benefit or cost may be relevant but not material. *Material* impacts are those that are expected to be of sufficient magnitude to affect the result of a BCA. Impact determined to be immaterial should be documented, but not necessarily included in the application of the BCA test.

Secondary BCA Tests

The NSPM also provides guidance on how secondary tests can be used to help assess marginally cost-effective DERs or to prioritize across DERs. While a jurisdiction's primary test should be used to inform whether a utility should fund or otherwise support DERs, it does not have to be utilized in a vacuum. In some instances, secondary tests can help enhance regulators' and stakeholders' overall understanding of DER impacts by answering other questions regarding utility DER investments. Different tests provide different information about the cost-effectiveness and impacts of DERs. However, secondary tests should be used cautiously to ensure that they do not make the BCA decision-making process burdensome or undermine the purpose of the primary test.

This manual does not prescribe any one cost-effectiveness test. Because the JST is based upon each jurisdiction's applicable policy goals, and those goals can vary across jurisdictions, the test may take a variety of forms. Further, depending on a jurisdiction's applicable policy goals, the primary test may or may not align with traditional BCA tests (e.g., the Total Resource Cost test.)

Part II. DER Benefits and Costs and Cross-Cutting Considerations

Part II of the manual presents a catalog of the full range of benefits and costs that may be applicable to specific types of DERs. This catalog can be used as a reference when deciding which types of benefits and costs should be included in a jurisdiction's BCA test.

The catalog of impacts is presented in table format and supported with detailed descriptions of each impact type. Table S-3 shows the range of potential DER impacts to the electric utility system, along with descriptions of each impact. Similarly, Table S-4 and Table S-5 provide a summary of potential host customer and societal impacts, respectively. Part II also addresses natural gas and other fuel system impacts and specific host customer non-energy impacts (NEIs).

Table S-3. Potential DER Impacts: Electric Utility System

Type	Utility System Impact	Description
Generation	Energy Generation	The production or procurement of energy (kWh) from generation resources on behalf of customers
	Capacity	The generation capacity (kW) required to meet the forecasted system peak load
	Environmental Compliance	Actions to comply with environmental regulations
	RPS/CES Compliance	Actions to comply with renewable portfolio standards or clean energy standards
	Market Price Effects	The decrease (or increase) in wholesale market prices as a result of reduced (or increased) customer consumption
	Ancillary Services	Services required to maintain electric grid stability and power quality
Transmission	Transmission Capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably
	Transmission System Losses	Electricity or gas lost through the transmission system
Distribution	Distribution Capacity	Maintaining the availability of the distribution system to transport electricity or gas safely and reliably
	Distribution System Losses	Electricity lost through the distribution system
	Distribution O&M	Operating and maintaining the distribution system
	Distribution Voltage	Maintaining voltage levels within an acceptable range to ensure that both real and reactive power production are matched with demand
General	Financial Incentives	Utility financial support provided to DER host customers or other market actors to encourage DER implementation
	Program Administration	Utility outreach to trade allies, technical training, marketing, and administration and management of DERs
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of DER programs
	Credit and Collection	Bad debt, disconnections, reconnections
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks
	Reliability	Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions

Table S-4. Potential Benefits and Costs of DERs: Host Customer

Type	Host Customer Impact	Description
Host Customer	Host portion of DER costs	Costs incurred to install and operate DERs
	Host transaction costs	Other costs incurred to install and operate 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
	Host Customer NEIs	Benefits and costs of DERs that are separate from energy-related impacts
	Low-income NEIs	Non-energy benefits and costs that affect low-income DER host customers

Table S-5. Potential Costs and Benefits of DERs: Societal

Type	Societal Impact	Description
Societal	Resilience	Resilience impacts beyond those experienced by utilities or host customers
	GHG Emissions	GHG emissions created by fossil-fueled energy resources
	Other Environmental	Other air emissions, solid waste, land, water, and other environmental impacts
	Economic and Jobs	Incremental economic development and job impacts
	Public Health	Health impacts, medical costs, and productivity affected by health
	Low-Income: Society	Poverty alleviation, environmental justice, and reduced home foreclosures
	Energy Security	Energy imports and energy independence

In addition to describing the range of potential DER impacts, Part II also addresses key cross-cutting benefit and cost issues, including the following:

- *Temporal and Locational Impacts of DERs*: Several of the benefits and costs of some DERs can vary significantly depending on when the DER operates and where it is located. DER benefits and costs should be estimated using temporal and locational detail sufficient to adequately represent the DER operating patterns and consequent benefits and costs.
- *Interactive effects between individual DERs*: Some DERs can have interactive effects on other DERs in terms of affecting avoided costs, affecting the magnitude of kWh and kW impacts, and enabling the adoption of other DERs. These interactive effects should be accounted for in BCAs for those instances where they are likely to have a material effect.

- *Air emission impacts*: Greenhouse gas (GHG) and other air emission impacts will depend upon when the DER operates and which energy resources are displaced at that time. Estimates of GHG and other air emission impacts should account for the temporal and marginal DER impacts in as much detail as necessary to reflect these effects.
- *Renewable generation impacts*: DERs can support renewable electricity generation by providing grid flexibility and ancillary services. DERs can also reduce (or increase) the need to curtail renewable resources during times when renewable generation exceeds customer load. These impacts on renewable generation should be accounted for when they are expected to have a material effect on the BCA results.
- *Discount rates*: The choice of discount rate to use for a BCA can often have a very large effect on the result of the analysis. This choice should be guided by the jurisdiction's applicable policy goals and the regulatory perspective.

DER impacts identified for inclusion in a jurisdiction's BCA should ideally be estimated in monetary terms. Monetary values provide a uniform way to compile, present, and compare benefits and costs. While some DER impacts are difficult to quantify in monetary terms—either due to the nature of the impact or the lack of available information about the impacts—approximating hard-to-quantify impacts using best available information is preferable to arbitrarily assuming a value, including assuming that the relevant impacts do not exist or have no value. Further, some approximation may be necessary to ensure symmetry in the treatment of benefits and costs for certain relevant impacts.

Part III: BCA for Specific DER Types

Part III of the NSPM contains five chapters that discuss individual characteristics and impacts of each DER type covered in this manual: EE, DR, DG, DS, and electrification (including managed charging and discharging of EVs). Part III describes and provides guidance on key factors and challenges that affect the impacts of each DER type.

Table S-6, Table S-7, and Table S-8 show the range of benefits and costs in terms of their applicability to each DER. They indicate which impacts are typically a benefit, a cost, or either depending on the specific DER use case. The tables are a compilation of the DER-specific tables presented in Chapters 6–10 of the manual.

Table S-6. Potential Benefits and Costs: Electric Utility System

Type	Utility System Impact	EE	DR	DG	Storage	Electrification
Generation	Energy Generation	🟢	🟠	🟢	🔴	🔴
	Capacity	🟢	🟢	🟢	🟠	🔴
	Environmental Compliance	🟢	🟠	🟢	🟠	🔴
	RPS/CES Compliance	🟢	🟠	🟢	🔴	🔴
	Market Price Effects	🟢	🟢	🟢	🟠	🔴
	Ancillary Services	🟢	🟢	🟠	🟠	🔴
Transmission	Transmission Capacity	🟢	🟢	🟠	🟠	🟠
	Transmission System Losses	🟢	🟢	🟢	🟠	🔴
Distribution	Distribution Capacity	🟢	🟢	🟠	🟠	🔴
	Distribution System Losses	🟢	🟢	🟢	🟠	🔴
	Distribution O&M	🟢	🟢	🟠	🟠	🔴
	Distribution Voltage	🟢	🟢	🟠	🟠	🔴
General	Financial Incentives	🔴	🔴	🔴	🔴	🔴
	Program Administration Costs	🔴	🔴	🔴	🔴	🔴
	Utility Performance Incentives	🔴	🔴	🔴	🔴	🔴
	Credit and Collection Costs	🟢	🟢	🟢	🟢	🟢
	Risk	🟢	🟢	🟠	🟢	🔴
	Reliability	🟢	🟢	🟠	🟢	🔴
	Resilience	🟢	🟢	🟢	🟢	○

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type

Table S-7. Potential Benefits and Costs of DERs: DER Host Customer

Type	Host Customer Impact	EE	DR	DG	Storage	Electrification
Host Customer	Host portion of DER costs	🔴	🔴	🔴	🔴	🔴
	Interconnection fees	○	○	🔴	🔴	○
	Risk	🟢	○	🟠	🟢	🟠
	Reliability	🟢	🟠	🟢	🟢	🟠
	Resilience	🟢	🟠	🟢	🟢	🟢
	Tax Incentives	🟢	🟢	🟢	🟢	🟢
	Host Customer NEIs	🟠	🟠	🟠	🟠	🟠
	Low-income NEIs	🟢	🟢	🟢	🟢	🟢

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type

Table S-8. Potential Benefits and Costs of DERs: Societal

Type	Societal Impact	EE	DR	DG	Storage	Electrification
	Resilience	🟢	🟢	🟢	🟢	🟠
	GHG Emissions	🟢	🟠	🟢	🟠	🟠
	Other Environmental	🟢	🟠	🟢	🟠	🟠
	Economic and Jobs	🟢	🟢	🟢	🟠	🟠
	Public Health	🟢	🟠	🟢	🟠	🟠
	Low Income: Society	🟢	🟢	🟢	🟢	🟢
	Energy Security	🟢	🟢	🟢	🟠	🟢

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type

Part IV: BCA for Multiple DER Types

The manual addresses BCA for different applications where multiple DER types might be combined, including:

- multiple on-site DER types, such as grid-integrated efficient buildings (GEB);
- multiple DER types in a specific geographic location in the form of a non-wires solution (NWS);
- multiple DER types across a utility service territory; and
- dynamic system planning practices that can be used to optimize DERs and alternative resources.

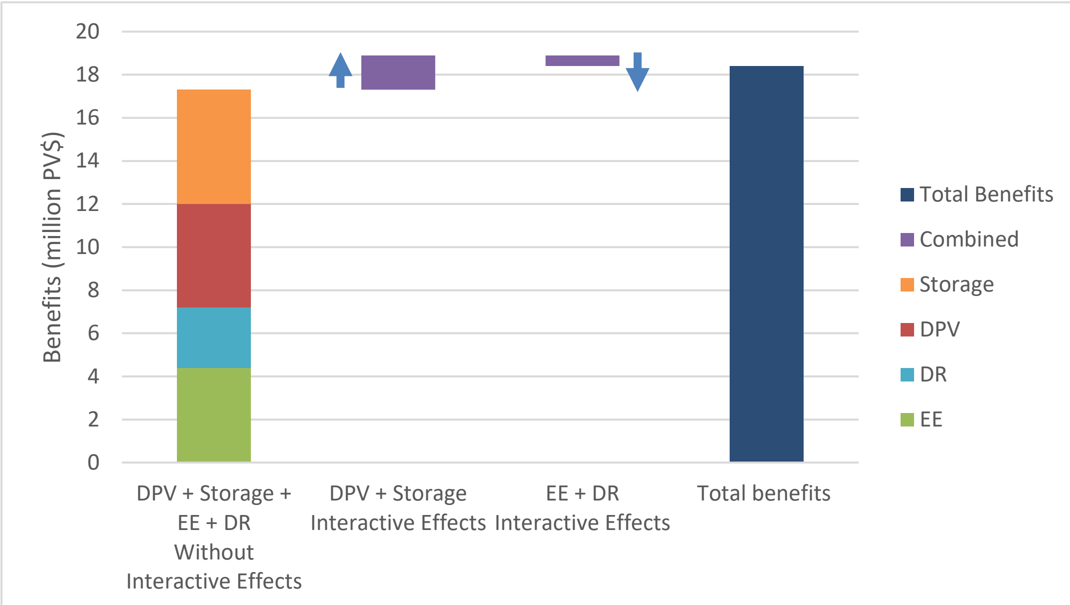
Multiple On-site DERs

Multiple on-site DERs can be installed in a variety of ways:

- On a residential level, utilities programs provide incentives to adopt multiple DER types that can then be used to benefit the customer and the grid.
- On a residential and commercial level, the aggregation of DERs in grid-interactive efficient buildings (GEBs) can provide grid support at scale.
- On a community level, DERs in microgrids and smart neighborhoods can be aggregated to provide grid support at scale.

The potential benefits and costs of multiple on-site DERs will depend on the type of DERs deployed, their capabilities, locational and temporal impacts, seasonal and daily load profiles, resource ownership and control of the DERs (i.e., level of dispatchability), and interactive effects across the DERs. Figure S-2 shows how the interactive effects between distributed photovoltaics and storage and between EE and DR can affect the total benefits of a GEB.

Figure S-2. Interactive Effects in Grid-Interactive Efficient Building



Non-Wires Solutions

These solutions focus on instances where utilities or others seek to install multiple DER types in a specific geographic area for the purpose of deferring or avoiding new investments in distribution or transmission systems. In these cases, cost-effectiveness will be very project-specific, depending on the specific transmission or distribution upgrade being deferred, the length of deferral, the mix of DERs producing the deferral, and a range of other factors. Due to the nature of T&D deferrals and uncertainty of load forecasts, NWS BCAs account for a project's number of years of deferral, which can shift depending on changing load forecasts.

Other key considerations for BCAs of NWSs include:

- When NWS projects are based on existing or new customer-sited DER programs, it is critical to accurately forecast customer participation and adoption, to reduce risk of not meeting requirements.
- Interactive effects should be accounted for, including effects on avoided costs, effects on kWh or kW impacts, and enabling effects.
- DERs geographically deployed to defer a T&D upgrade can have broader impacts on the utility system (e.g., avoided energy and generation capacity costs) as well as broader impacts related to policy objectives (e.g., avoided emissions).

<u>Illustrative Example of BCA for an NWS Project</u>

This manual provides an illustrative example of how a jurisdiction's primary test developed using NSPM can be applied to a hypothetical NWS project. The example assumes that a hypothetical state has developed its primary cost-effectiveness test (or modified its existing primary test) using the 5-step process described in Table S-2.

The state's JST accounts for conventional overarching goals of providing safe, reliable, resilient, and reasonably priced electricity services, as well as the goal of reducing GHG emissions (as articulated in statute). The JST also accounts for host customer impacts.

Non-Wires Solution Case Study Assumptions

In this example, an electric utility is facing the need to upgrade its system infrastructure due to distribution capacity constraints identified in a densely populated geographic area within its service territory. The utility proposes to integrate DERs to serve as a non-wires solution in place of an infrastructure upgrade.

The NWS plan includes the following BTM DERs in residential and commercial buildings:

- Energy efficiency measures (e.g., lighting and controls)
- Demand response (e.g., Wi-Fi-enabled thermostats)
- Distributed photovoltaics
- Distributed storage systems

Jurisdiction-Specific Test: The hypothetical jurisdiction's primary BCA test accounts for utility system, host customer, and GHG emission impacts.

Key assumptions:

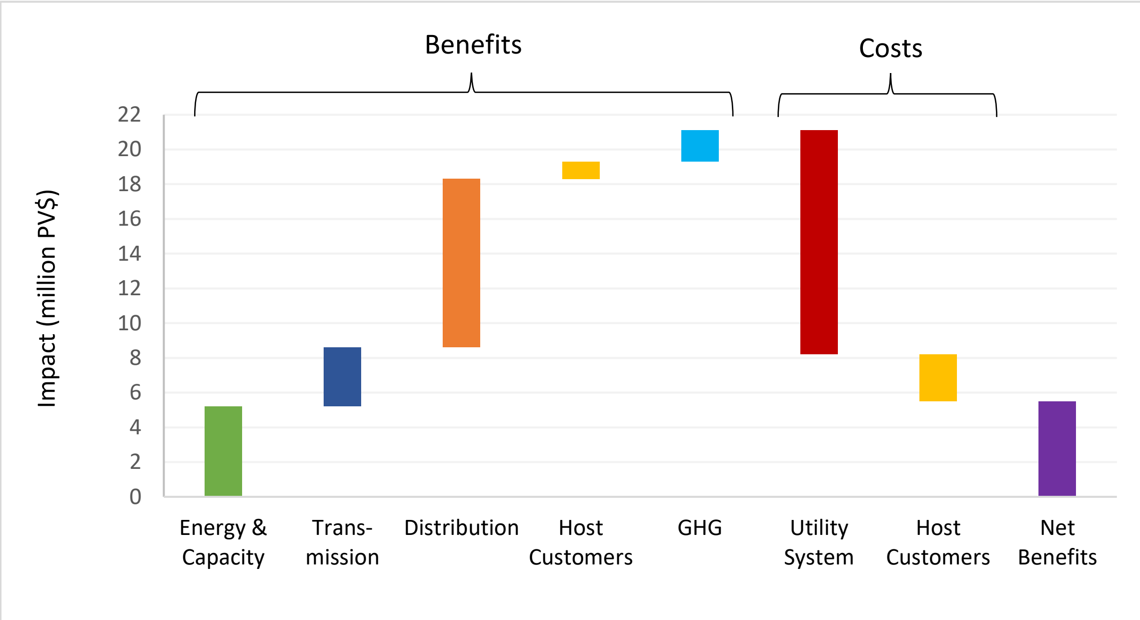
- *Non-Coincident Peak:* The distribution need is non-coincident with the overall system peak (e.g., the constrained distribution feeder peaks from 1:00–5:00pm, while system peaks from 5:00–9:00pm).
- *GHG Emissions Reduction:* The system-peak hours entail higher marginal emissions rates than the NWS, which allows the NWS to deliver GHG benefits.
- *DER Operating Profiles:* The NWS DERs operate in the following ways:
    - All DERs are operated to reduce the distribution peak, and some can reduce the system peak as well.
    - Storage charges during the distribution off-peak hours and discharges during the distribution peak hours.
    - DR reduces demand during distribution peak periods and/or shifts load from distribution peak periods to distribution off-peak periods.
    - Distributed PV resources generate during a portion of distribution peak period.
    - EE helps to reduce demand during distribution peak periods.

The example NWS benefits and costs associated with utility system, host customer, and GHG impacts are summarized below and presented in Figure S-3.

- *Generation Benefits* – Some generation benefits (e.g., energy generation, capacity, and ancillary services) accrue from targeting operation of DERs, such as storage and DR, during distribution peak periods. There will be additional benefits that result from some DERs—such as DPV and EE—also operating during other off-peak periods.
- *Transmission Benefits* – Some transmission benefits (e.g., capacity and system losses) accrue with the reduced delivery of central generation to customers.
- *Distribution Benefits* – The greatest contributor to the overall cost-effectiveness analysis is the direct benefit of operating DERs as much as possible during distribution peak periods.
- *GHG Benefits* – In this example, the GHG emissions are higher during the distribution system peak periods than the other periods. Consequently, the peak demand reductions from the NWS will result in a net reduction in GHG emissions.
- *General Utility Costs* – Financial incentives for customers to participate and administrative costs lead to the more substantive general utility costs for this illustrative analysis.
- *Host Customer Impacts* – Host customer costs include interconnection fees, transaction costs, and DER costs, while benefits include various non-energy impacts.

Figure S-3 combines the net benefits and costs of utility system, host customer, and GHG impacts. In this case study, locational value plays a central role in the cost-effectiveness of an NWS, as represented by the significant distribution benefits. The BCA indicates that the NWS will have net benefits.

Figure S-3. Illustrative Example of NWS Cost-Effectiveness



System-Wide DER Portfolios

The NSPM provides guidance on how to analyze and prioritize a portfolio of multiple DER types across a utility service territory.

In analyzing portfolios of multiple DER types across a utility service territory, it is important to first establish a single primary cost-effectiveness test that can be used for all DER types. Then, it is useful to articulate the jurisdiction's DER planning objectives, which can include, for example, one or some combination of: implement all cost-effective DERs; implement the lowest-cost DERs; maximize capacity benefits from DERs; encourage a diverse range of DER technologies; encourage customer equity; achieve GHG or electrification goals at lowest cost; and avoid unreasonable rate impacts.

Utilities and others can present the BCA results for DER portfolios in ways that facilitate comparison across DER types, such as:

- DERs can be ranked by benefit-cost ratios or net benefits to indicate the most cost-effective resources.
- Levelized DER costs can be used to directly and consistently compare costs across different DER types.
- Levelized net cost curves can be used to compare and prioritize DERs according to key parameters such as $/ton GHG reduced.
- Multiple cost-effectiveness tests, in addition to the JST, can provide additional information when analyzing portfolios of multiple DER types.

Figure S-4. Example DERs Sorted by Net Benefit

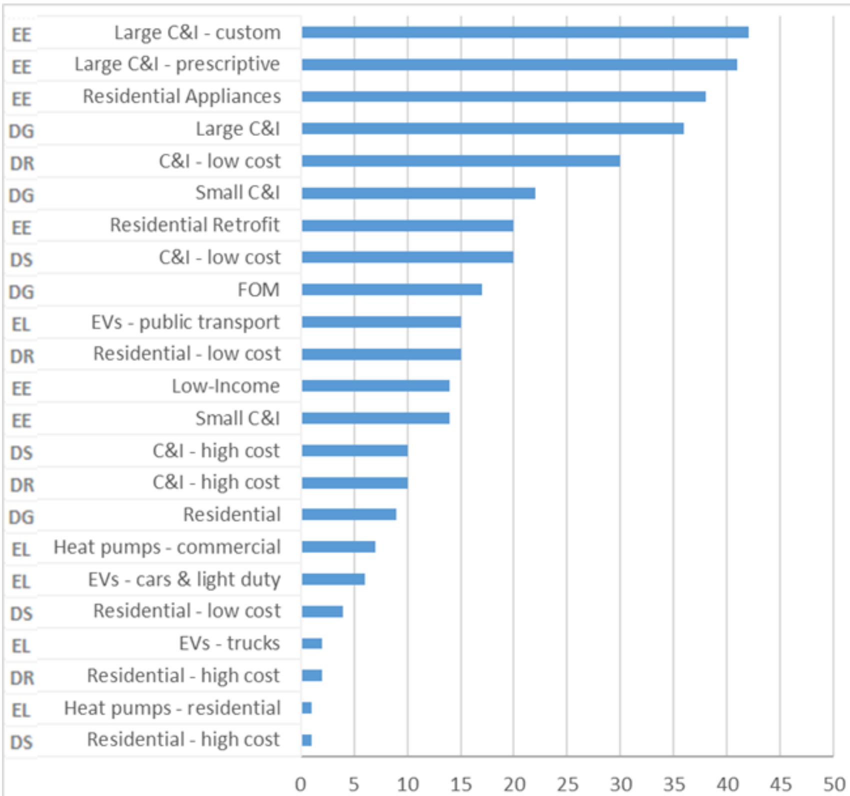


Figure S-4 presents a list of hypothetical DERS sorted by the net benefits that they provide. This information could be used to identify those DERs that warrant utility support or funding in order to achieve the greatest net benefits for a given level of funding. A similar approach could be used to prioritize BCRs by their benefit-cost ratios, or to prioritize DERs for within a given rate impact cap.

In some cases, a jurisdiction may prefer to invest in a diverse range of DER types on the basis that all DER types contribute benefits in different ways and there is value in promoting a diversity of technologies, as well as reducing associated system risk. In such a case, regulators might decide to support a minimum amount of each type of DER. This could be achieved by sorting the DER types by net benefits or benefit-cost ratios and selecting the lowest cost options for each type of DER.

Dynamic System Planning

Utilities have conducted traditional distribution system planning for many years to determine how to best to build and maintain the distribution grid. The focus of this practice has been on providing safe, reliable power through the distribution grid at a low cost. It typically has not accounted for DERs as alternatives to traditional distribution system technologies. However, the scope of utility system planning is expanding to manage the increasing complexity of the electricity system, while addressing evolving state policy objectives, changing customer priorities, and increased DER deployment. The manual provides an overview of evolving advanced planning practices that can allow utilities to more effectively and dynamically optimize DERs using *dynamic system planning*.

Table S-9 summarizes several different types of planning practices used by electric and gas utilities. It presents practices according to whether they are used by distribution-only or vertically integrated utilities, and it shows what elements of the utility system are accounted for by each type of practice.

Each type of planning practice uses some form of BCA for comparing and optimizing different resources. Each practice is a type of dynamic system planning described above, where the resources of interest are optimized relative to a dynamic set of alternative resources.

Table S-9. Types of Dynamic System Planning Practices

Type of Utility System	Planning Practice	Planning Practice Accounts for: Distribution System	DERs	Transmission System	Utility-Scale Generation
Distribution-only & vertically integrated	Traditional distribution planning	✓	-	-	-
	Integrated distribution planning (IDP)	✓	✓	-	-
Vertically integrated	Transmission planning	-	-	✓	-
	Integrated resource planning (IRP)	-	✓	-	✓
	Integrated grid planning (IRP)	✓	✓	✓	✓

Dynamic system planning practices have evolved in recent years to optimize DERs and maximize their value to the system. These include integrated distribution planning (IDP) for distribution-level planning only and integrated grid planning (IGP) for full-system planning.

Appendices

Table S-10 summarizes the appendices that provide further detail on some NSPM topics that warrant additional explanation.

Table S-10. Guide to Appendices

Part V	Appendices	
Appendix A	Rate Impacts	Describes the difference between cost-effectiveness and rate impact analyses, as well as the role of rate, bill, and participation analyses
Appendix B	Template NSPM Tables	Tables that can be used by jurisdictions to document applicable policies and relevant benefits and costs to inform their BCAs
Appendix C	Approaches to Accounting for Relevant Impacts	Provides guidance on options to account for relevant benefits and costs, including hard-to-quantify impacts and non-monetary impacts
Appendix D	Presenting BCA Results	Provides guidance on presenting results in a way that is most useful for making cost-effectiveness decisions
Appendix E	Traditional Cost-Effectiveness Tests	Summarizes the commonly used traditional cost-effectiveness tests from the *California Standard Practice Manual*
Appendix F	Transfer Payments and Offsetting Impacts	Provides guidance on impacts that appear to be both a benefit to one party and a cost to another party, thereby cancelling each other out
Appendix G	Discount Rates	Describes ways to determine discount rates that are consistent with the jurisdiction's applicable policy goals
Appendix H	Energy Efficiency—Additional Guidance	Describes how to address free-riders and spillover effects where net savings are used; and treatment of early replacement measures

GLOSSARY

Advanced metering infrastructure (AMI): an integrated system of smart meters and data management systems that enables two-way communication between utilities and customers.

Aggregator: a company that negotiates with producers of a utility service such as electricity on behalf of groups of consumers, or which bundles DERs to engage as a single entity—a virtual power plant (VPP)—in power or service markets.

Alternative thresholds: an approach to address hard-to-monetize impacts that allow DERs to be considered cost-effective at pre-determined benefit-cost ratios. (See Appendix C.)

Analysis period: the time period over which cost-effectiveness analysis should be conducted. (See "Expected useful life" and Appendix H.)

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.

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. (See Chapter 4.)

Behind the meter (BTM): Also referred to as "customer-facing," BTM includes a range of technologies that customers can install to reduce the host customers' bills and/or improve the operational efficiency of the distribution system, thus also sometimes providing value to the grid. This includes all types of DERs, such as EE, DR, DG, DS, electrification, and EVs.

Benefit-cost analysis (BCA): 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. (See Section 1.3.)

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. (See "Electrification" and Chapter 10.)

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 (DR): DR programs play a role in the operation of the electric grid by reducing or shifting their electricity usage during peak periods in response to time-based rates or other forms of financial incentives. DR programs are used by some electric system planners and operators as resource options for balancing supply and demand. Methods of engaging customers in DR efforts include offering time-based rates and direct load control programs which provide the ability for power companies to e.g., cycle air conditioners and water heaters on and off during periods of peak demand in exchange for a financial incentive and lower electric bills. (NERC 2011) (See Chapter 7.)

Discount rates: a component of cost-effectiveness analysis which reflects a "time preference"—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 gives greater weight to long-term impacts. (See Appendix G.)

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 (DER): 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 (DOE 2019a. These include EE, demand response, distributed generation, storage, plug-in electric vehicles, strategic electrification technologies, and more.

DER pricing mechanism: includes initiatives and performance-based compensation to encourage customers to install and utilize DERs as efficiently as possible through price signals. Examples include time-based pricing (time-of-use or TOU rates, peak time rebates, and critical peak pricing) and net metering compensation.

DER programs: include passive and performance-based programs, initiatives, and policies that encourage customers to adopt DERs. Examples include traditional utility EE programs, traditional utility DR or bring-your-own-device (BYOD) programs, distributed storage incentives, and investments in EV infrastructure.

DER procurement: includes initiatives to procure DERs, whether built by a utility or procured from third-party vendors, e.g., competitive and/or technology providers, typically using a competitive procurement process.

Distributed generation (DG): electric generation interconnected to the distribution grid and operating at the distribution level, generally near a load, though sometimes stand-alone. DG includes distributed solar photovoltaic (PV/DPV) technology, combined heat and power (CHP), district heating and cooling, small wind, and biomass and biogas facilities associated with landfills and agricultural operations. (See Chapter 8.)

Distributed storage (DS): technologies used to locally store energy. This manual 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). (See Chapter 9.)

Double-counting: the inclusion of overlapping impacts in analyses, and thus counting one effect more than once.

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. See "Vehicle to Grid" and "Electrification" and Chapter 10.

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 EVs. This can be "partial," where some but not all fuel consumption is replaced by electricity (e.g., a plug-in hybrid EV), or "complete" (e.g., a battery electric vehicle). (See Chapter 10.)

Enabling effects: when some DERs make it easier or more cost-effective to adopt other types of DERs. (See Section 11.5.)

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. (See Chapter 6.)

Forward-looking analysis: captures the difference between benefits and costs that would occur over the lifetime of the DERs and those what would occur absent the DERs.

Free-ridership: DER savings that would have occurred in the absence of the program.

Front of the meter (FOM): also known as utility-facing, FOM DERs are typically operated to reduce system costs (as opposed to BTM DERs, which are typically operated to reduce customer costs). (See Chapter 5.)

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.

Grid-interactive efficient building (GEB): an energy-efficient building that uses smart technologies and on-site DERs to provide demand flexibility while co-optimizing for energy cost, grid services, and occupant needs and preferences in a continuous and integrated way (DOE 2019a). (See Chapter 11.)

Grid modernization: investments in updating the grid to accommodate DERs, multi-way power flows, and/or active management of the distribution grid to achieve reliability and greater efficiency (DOE 2017b). These are often categorized as either utility-facing, which may support increased DER implementation, or customer-facing, which often include a range of DERs.

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 DR or EE program. In other cases, there is no program, e.g., EV owners.

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 (see Table 1-1 and Chapter 14).

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) (see Table 1-1 and Chapter 14).

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 (see Table 1-1 and Chapter 14).

Long-run: the period covering the full life cycle of the resource being analyzed. The long-run approach is necessary to account for the full benefits and costs of the DER being evaluated, particularly since energy resources, including many DERs, can last decades.

Lost revenues: 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. (See Chapter 4.)

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: represent the average cost per unit of energy required to install and operate an electricity or gas resource. 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.

Material impacts: impacts that are expected to be of sufficient magnitude to affect the result of a BCA.

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." (See Chapter 11.)

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. GEB), for a certain geographic area to identify non-wires solutions, and/or across the entire utility system. (See Chapters 11–13.)

Net energy metering (NEM): also known as net metering, tariff design that allows consumers to receive bill credit on a kWh basis for excess generation injected onto the grid for the use of other customers. (See Chapter 8.)

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 (NEI): 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 economic development, and reduced risk of utility service disruptions or price spikes.

Non-pipes solution: 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 solution (NWS): also known as non-wires alternative (NWA), 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. (See Chapter 12.)

Participant Cost Test (PCT): a cost-effectiveness test, as provided in the 2001 *California Standard Practice Manual*, which 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.

Policy neutrality: a core component of the NSPM guidance. The NSPM does not advocate for any policy or cost-effectiveness test, but rather that a jurisdiction applies the NSPM BCA Framework to review its existing policies to develop a cost-effectiveness test which reflects local policy objectives.

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.

Proxies: simple, quantitative values that can be used as indirect indicators for values not monetized by conventional means, which can be applied to any type of benefit or cost that is hard to monetize and is expected to be of significant magnitude. (See Appendix C.)

Rate, bill, participant 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. See "Rate Impact Analysis," "Bill Impact Analysis," and "Participation Impact Analysis."

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. See Appendix A.

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.

Revenue shifting: occurs when reduced consumption from DERs shifts the collection of revenues from DER customers to others but does not increase rates. This can be caused by downward pressure on rates created by avoided utility system costs exceeding the upward pressure on rates from reduced sales. Not to be conflated with cost-shifting, which occurs when reduced consumption from DERs shifts collection of revenues from DER customers to others but increases rates. (See Appendix A.)

Secondary cost-effectiveness test: a cost-effectiveness test that supports use of the primary test by helping enhance stakeholders' overall understanding of DER impacts by answering additional questions regarding utility DER investments. The impacts included in secondary tests are driven by the purpose of the secondary analyses, including informing decisions on how to prioritize DERs; informing decisions regarding marginally cost-effective DERs; encouraging consistency across DER types; and considering other types of effects on customers. (See Section 3.3 and Appendix D.)

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. (See Chapters 6–10.)

Smart neighborhoods or communities: a set of homes or buildings that include GEB characteristics that can be connected as a neighborhood-style microgrid (DOE 2019c). (See Chapter 11.)

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.

Spillover: installation of DERs by customers who did not directly participate in a DER program but were nonetheless influenced by the program.

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. (See Chapter 2.)

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.

Transfer payment: a one-way payment of money for which no money, good, or service is received in exchange. This is uncommon in DER BCAs. (See Appendix F.)

Transparency: a key principle whereby cost-effectiveness practices fully document all relevant inputs, assumptions, methodologies, and results. (See Appendix B and Appendix D for recommended templates and reporting formats.)

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.

Vehicle to grid (V2G): a two-way flow capability in some EVs that allows EVs to function as storage devices that can push electricity back onto the grid, thus potentially reducing net system peak demands and/or net T&D peak demands. (See "Electrification" and Chapter 10.)

Virtual power plants (VPP): a suite of DERs optimized by software and advanced communication systems that aggregate, control, dispatch, and/or plan deployment to provide services similar to a conventional power plant. (See Chapter 12.)

ACRONYMS

AC	Avoided costs	**JST**	Jurisdiction-Specific Test
AMI	Advanced metering infrastructure	**kW**	Kilowatt
BCA	Benefit-cost analysis	**kWh**	Kilowatt-hour
BCR	Benefit-cost ratio	**LBNA**	Locational net benefit analysis
BEV	Battery electric vehicle	**LCOE**	Levelized cost of energy or electricity
BTM	Behind the meter	**LCSE**	Levelized cost of saved energy
BTU	British thermal units	**LED**	Light-emitting diode
BYOD	Bring your own device	**LSE**	Load serving entity
BYOT	Bring your own thermostat	**MLP**	Municipal light plant
CES	Clean energy standard	**MMBtu**	Million British thermal units
CHP	Combined heat and power	**MW**	Megawatt
C&I	Commercial and industrial	**MWh**	Megawatt-hour
COP	Coefficient of performance	**NEIs**	Non-energy impacts
CPS	Clean peak standard	**NEM**	Net energy metering
CS	Community solar	**NPS**	Non-pipes solution
DCFC	Direct current fast chargers	**NWS**	Non-wires solution
DER	Distributed energy resources	**O&M**	Operations and maintenance
DG	Distributed generation	**PACT**	Program Administrator Cost Test
DPV	Distributed solar photovoltaic	**PCT**	Participant Cost Test
DR	Demand response	**PHEV**	Plug-in hybrid electric vehicle
DRP	Distribution resource plan	**PV**	Solar photovoltaic
DS	Distributed storage	**REC**	Renewable energy credit
DSP	Distribution system planning	**RIM**	Rate Impact Measure Test
EE	Energy efficiency	**RPS**	Renewable portfolio standard
EL	Electrification	**RR**	Retail rate
EM&V	Evaluation, measurement, and verification	**RTO**	Regional transmission organization
EV	Electric vehicle	**SCT**	Societal Cost Test
FIT	Feed-in tariffs	**TOU**	Time of use
FOM	Front of the meter	**TRC**	Total Resource Cost (Test)
FTR	Fixed transmission rights	**T&D**	Transmission and distribution
GEB	Grid-interactive efficient building	**UCT**	Utility Cost Test
GHG	Greenhouse gas	**VAR**	Voltage levels and reactive power
HVAC	Heating, ventilation, and air conditioning	**VDER**	Value of distributed energy resources
IDP	Integrated distribution planning	**VNM**	Virtual net metering
IGP	Integrated grid planning	**VOS**	Value of solar
IOU	Investor-owned utilities	**VPP**	Virtual power plants
IRP	Integrated resource planning	**V2G**	Vehicle to grid
ISO	Independent system operator	**WACC**	Weighted average cost of capital
ITC	Federal Investment Tax Credit		

1. INTRODUCTION

This chapter describes the purpose and scope of this manual. It provides an overview of benefit-cost analysis (BCA) and describes the format of this manual.

1.1 Distributed Energy Resources - Overview

DERs are resources located on the distribution system that are generally sited close to or at customers' facilities. The DERs addressed in this manual include energy efficiency (EE), demand response (DR), distributed generation (DG), distributed storage (DS), electric vehicles (EV), and building electrification.

The electricity and gas industries are increasingly planning for and implementing distributed energy resources (DERs) to meet demand flexibility and other utility system resource needs. This change is driven largely by changing economics, customer preferences and demand, and a range of policy goals and objectives. In this evolving landscape, applying a comprehensive and consistent benefit-cost analysis framework (BCA Framework) to analyze investments in DERs can help jurisdictions implement optimal levels of DERs and avoid uneconomic decisions that can lead to unintended increased costs for customers.

Investments in DERs—whether in the form of programs, procurement, or pricing mechanisms—are made for multiple purposes, either independently or in some combination, to meet a range of policy goals and objectives. These purposes can include, for example, reducing utility system costs, deferring capacity, providing demand flexibility, increasing reliability, reducing energy burdens for low- to moderate-income customers, managing grid power quality, and/or achieving carbon emission reduction goals.

Generally, DERs represent a critical component of the evolution of the electricity grid, allowing for a more flexible grid, enabling two-way flows of energy, enabling third parties to introduce and sell new electricity products and services, and empowering customers to optimize their end-uses and consumption patterns to lower their bills and utility costs. Additionally, the flexible loads that DERs can provide or support are increasingly being considered by states as an option to enable the integration of variable-generation renewable energy resources to achieve a carbon-free grid.

This manual sets forth the NSPM BCA Framework and supporting concepts and guidance for sound, comprehensive, and balanced assessment of the benefits and costs of DERs. While the manual does not address every nuance or scenario for DER investments, the NSPM can help jurisdictions identify the full range of DERs whose benefits exceed their costs and develop BCA practices that are most appropriate for their jurisdictions given their goals and objectives.

The NSPM can help jurisdictions identify the full range of DERs whose benefits exceed their costs and develop BCA practices that are most appropriate for their jurisdictions given their goals and objectives.

1.2 Audience and Terminology

The NSPM is intended to be relevant to all jurisdictions, and to all entities that have a role overseeing and guiding DER decision-making.

This manual is relevant to all DERs that are funded, acquired, or otherwise supported by electric or gas utilities (or other energy providers) on behalf of their customers.

The NSPM applies to all types of utilities, including those in regions where utilities are vertically integrated, distribution-only, or serving as a distribution platform for host customers to access a variety of energy services and DERs from third parties (e.g., aggregators.)

This manual uses many terms that are commonly used within the electricity and gas industries. Key terms are defined in a Glossary and in relevant sections of the manual. Some of the terms used in the manual are more broadly defined than in other applications, as noted in the text box below.

KEY TERMS USED THROUGHOUT THIS MANUAL

Jurisdiction refers broadly to any region or service territory that would be served by the DERs being analyzed. This includes a state, a province, a utility service territory, a city or a town, or some other jurisdiction covered by regulators or other entities that oversee DER initiatives.

Utility refers broadly to any entity that funds, implements, or supports DERs using customer or public funds that are overseen by regulators or other decision-makers. This includes investor-owned utilities; publicly owned utilities; municipal or cooperative utilities; program administrators; community choice aggregators; regional transmission organizations and independent system operators; federal, state, and local governments; and other energy service providers. *Utility expenditures* refers to spending by any of these entities on DERs.

Regulator refers broadly to any entity that oversees and guides DER analyses. This includes legislators and their staff; public utility commissions and their staff; boards overseeing public power authorities, municipal or cooperative utilities, or regional grid operators; and federal, state, and local governments.

Host customer refers to any customer that has a DER installed and/or operated on their site. In some cases, these are program participants (such as in a DR or EE program) while in other cases there is no program (such as with EV owners).

Third parties refer to the broad range of independent providers such as aggregators or implementation, service, or technology providers.

1.3 Role of Benefit-Cost Analysis

Benefit-cost analysis is a systematic approach for assessing the cost-effectiveness of investments by comparing the benefits and costs of alternative options. It is widely used by businesses for deciding whether to proceed with projects, investments, programs, initiatives, or other courses of action. The analysis entails identifying all the relevant benefits and costs of a project and determining whether the benefits exceed the costs over the lifetime of the expected program or project.

DER BCAs answer the fundamental question: *Which resources have benefits that exceed costs and therefore merit utility acquisition or support on behalf of their customers*?

BCA is frequently used by utilities, both for making internal resource investment decisions and to justify resource investment decisions to regulators and other stakeholders. BCA has been used for many years to demonstrate the cost-effectiveness of specific DER investments and is central to several utility planning practices used to optimize resource decisions, as described further below.

DER BCAs can provide a systematic way to compare DERs consistently and comprehensively with each other and with alternative resources. DER BCAs answer the fundamental question: *Which resources have benefits that exceed costs and therefore merit utility acquisition or support on behalf of their customers?* DER BCAs can also answer other related and overlapping questions, such as:

- How can DERs be used to reduce utility/power system costs?
- How can DERs be used to meet applicable policy goals (e.g., providing benefits to low-income customers, reducing consumption of other fuels, and reducing carbon emissions)?
- How will DERs affect host customers? How likely is it that host customers will adopt DERs?
- How cost-effective is one DER type relative to other types for a specific use case?
- How should investment in different DER types be prioritized?
- Which DERs should be implemented considering budgetary or other constraints?

Jurisdictions interested in potential rate impacts from DERs can also conduct rate, bill, and participation analyses. These analyses may be useful for informing decisions regarding utility investment in or support of DERs and can be complementary to BCAs. Rate impact analyses, however, answer different questions than BCAs and therefore should be conducted separately from BCAs. Section 2.3 and Appendix A provide further information on the distinction between BCAs and rate impact analyses.

1.4 Scope of this Manual

This NSPM is designed to provide objective, policy- and technology-neutral guidance that regulators, utilities, consumer advocates, DER proponents, state energy offices, and other stakeholders can apply using a systematic approach to develop BCA practices that inform decisions regarding which DERs merit acquisition or support from utilities.

This manual incorporates and expands upon the 2017 *NSPM for Assessing Cost-Effectiveness of Energy Efficiency Resources* (NSPM for EE).[1]

Types of DERs and Applications Covered in this Manual

DER refers to electricity and gas resources that include EE, DR, DG, distributed storage, plug-in EVs, electrification technologies, and others. DG includes distributed photovoltaics (DPV), combined heat power (CHP), distributed wind, distributed hydro, and distributed biomass.

DERs can be funded or otherwise supported by utilities or other energy providers through several mechanisms. The three primary mechanisms include:

- *DER programs:* This includes programs, initiatives, and policies implemented by utilities or others to encourage the adoption of DERs. Examples include utility EE programs, utility DR or bring your own device (BYOD) programs, DG programs, and distributed storage programs, and investments in EV infrastructure.

[1] For more information, see www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

- *DER procurement:* This includes initiatives to procure DERs, whether built by a utility or procured from third-party vendors, typically using a competitive procurement process.
- *DER pricing mechanism:* This includes pricing mechanisms designed to compensate DERs for their value to the grid, including time-varying rates (e.g., time-of-use rates, peak time rebates, and critical peak pricing) and distributed generation tariffs (e.g., net energy metering tariffs).

The NSPM focuses on DER programs because they are commonly subjected to administrative cost-effectiveness assessments. Nonetheless, the principles, concepts, and guidance offered in this manual apply to DER procurement and pricing mechanisms as well. This manual is neutral regarding the use of any of the above mechanisms or approaches to supporting investment in DERs.[2]

The NSPM focuses on electricity DERs because these are the most common types of DERs. Nonetheless, the principles, concepts, and guidance in the manual are also applicable to natural gas DERs.

The NSPM addresses DERs that affect multiple fuel types, including electricity, natural gas, oil, propane, and gasoline (i.e., applications where a DER, or combinations of DERs, affect multiple fuel types).

The concepts and guidance in the NSPM can be applied to both behind-the-meter (BTM) and front-of-the-meter (FOM) DERs, defined as:

- *Behind the meter:* These are DERs installed at host customer facilities, where the DER is installed on the host customer side of the utility service connection (i.e., behind the utility retail meter).
- *Front of the meter:* These are DERs installed on the distribution utility system near customer loads, but not at host customer facilities.

The NSPM is neutral regarding whether a DER should be located in front of or behind the meter.

Different Levels of DER Cost-Effectiveness Analysis

DERs can be analyzed for cost-effectiveness at three different levels (LBNL 2018):

- *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. This approach has been used for many years and is relatively simple compared to the multi-DER approaches described below. Chapters 6-10 include guidance for single-DER analysis of each DER type.
- *Multiple-DER analysis:* when multiple DER types are assessed and evaluated together, again 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 when analyzing (a) multiple DER types that are located at one customer site, for example in the context of grid-interactive efficient buildings; (b) multiple DER types that are located in a certain geographic area to identify non-wires solutions; and (c) multiple-DER types that are located across the entire utility system. Chapters 11–13 provide considerations and case studies for multiple-DER analysis.
- *Dynamic system planning:* when multiple DER types are assessed and evaluated relative to a dynamic set of alternative resources. Under this approach, the goal is to optimize both DERs and alternative utility-scale resources as well. Dynamic system planning practices to integrate DERs

[2] Some DER practices do not fall neatly into these categories. For example, demand response resources might be achieved through either utility programs or pricing mechanisms. Net metering and similar policies could be described as either a utility program or a pricing mechanism. These distinctions are not relevant for the purposes of this manual.

are relatively nascent and still evolving. Chapter 14 provides an overview of BCA issues related to dynamic system planning.

Electric and Gas System Planning Practices

DERs can also be analyzed using different planning practices. Table 1-1 summarizes several different types of planning practices used by electric and gas utilities.[3] It presents practices according to whether they are used by distribution-only or vertically integrated utilities, and it shows what elements of the utility system are accounted for by each type of practice. While distribution planning is applicable to both distribution-only and vertically integrated utilities, it is only the latter which also focus on transmission and resource planning.

Each of these types of planning practices uses some form of BCA for comparing and optimizing different resources. Each of these practices are a type of dynamic system planning described above, where the resources are optimized relative to a dynamic set of alternative resources.

Table 1-1. Types of Planning Practices

Type of Utility System	Planning Practice	Planning Practice Accounts for:			
		Distribution System	DERs	Transmission System	Utility-Scale Generation
Distribution-only & vertically integrated	Traditional distribution planning	✓	-	-	-
	Integrated distribution planning (IDP)	✓	✓	-	-
Vertically integrated	Transmission planning	-	-	✓	-
	Integrated resource planning (IRP)	-	✓	-	✓
	Integrated grid planning (IGP)	✓	✓	✓	✓

Dynamic utility planning practices are an area of growing importance. For example, the National Association of Regulatory Utility Commissioners (NARUC) and the National Association of State Energy Officials (NASEO) Task Force on Comprehensive Electricity Planning is exploring frameworks for greater alignment between long-term electricity resource planning and distribution system planning (NARUC, NASEO 2020).

This manual primarily focuses on single- and multiple-DER analyses since these are the most common BCA applications in use today. Chapter 14 provides an overview of dynamic planning practices and additional context on the evolution of system planning.

[3] Jurisdictions have adopted a range of terms to describe planning processes. This manual uses IDP to describe enhanced distribution planning processes that dynamically optimize DERs and IGP to describe aligned full-system planning processes that incorporate generation, transmission, and distribution, including DERs.

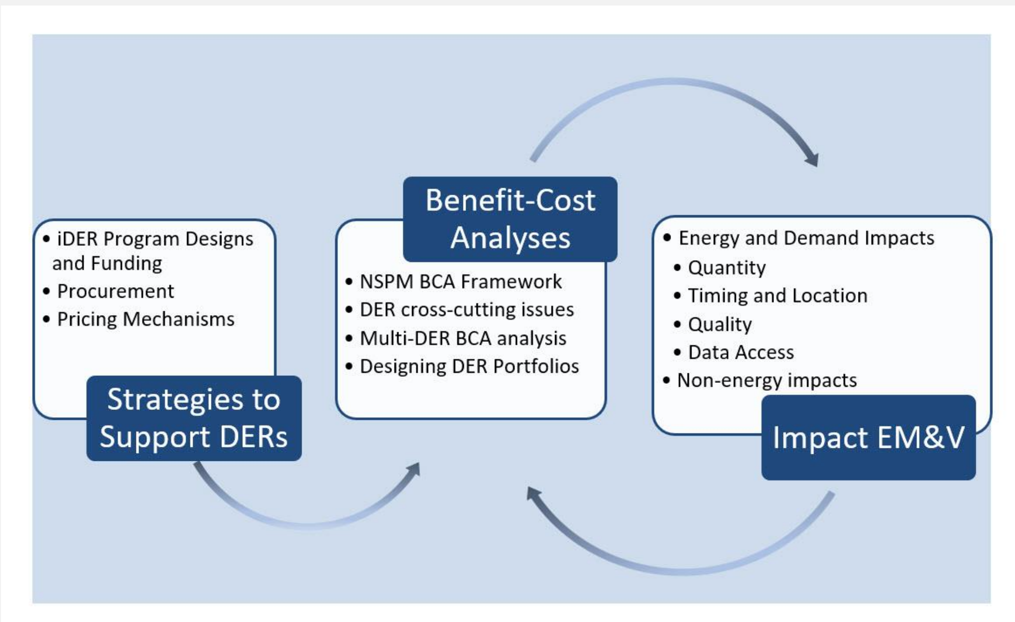
BCAs, Implementation Strategies, and EM&V

In addition to BCAs, utilities and others use DER implementation strategies and evaluation, measurement, and verification (EM&V) practices to plan for DERs. The DER implementation strategies include designing effective programs, procurement, and pricing mechanisms to help obtain or promote DERs, and the DER EM&V practices include the assessment of DER performance to determine actual values for achieved benefits and costs. The three approaches work together in an iterative fashion over time to help utilities plan for DERs.

Appropriate implementation strategies and EM&V practices are critical to the successful implementation of DERs, and they are each evolving with the changing roles of single and multiple DERs. For example:

- *DER Implementation Strategies* are changing with some program designs moving from siloed DER funding streams to more integrated procurement of DERs and innovative pricing mechanisms (SEE Action 2020b; SEA Action 2020c).
- *Evaluation, Measurement, and Verification (EM&V)* practices are evolving with the increased use of advanced metering and data analytics, both associated with a growing focus on DERs providing demand flexibility value in terms of temporal and locational impacts (SEE Action 2020a).

The NSPM is agnostic on use of any particular implementation strategy or EM&V approach. Coordinated evolution of the three areas can help to avoid unintended barriers to investment in DERs.



1.5 How to Use this Manual

This manual includes five parts:

- **Part I** presents the NSPM Benefit-Cost Analysis Framework, including fundamental principles and guidance on the development of primary and any secondary cost-effectiveness tests.
- **Part II** describes the full range of potentially relevant DER benefits and costs (i.e., impacts), and presents several cross-cutting considerations on how to account for certain impacts.
- **Part III** provides guidance on single-DER analysis for various types of DER technologies. These chapters discuss key factors that affect BCAs for each type of DER, identify BCA challenges and provide guidance on key issues.
- **Part IV** provides guidance on both multiple-DER analysis and dynamic system planning. It addresses the three main ways that multiple-DER analysis is conducted: for a customer site; for a geographic region; and for an entire utility service territory. Part IV also addresses dynamic system planning practices.
- **Appendices** provide further detail on some topics that warrant additional explanation. This includes information and template tables on reporting BCA results.

The process for conducting a BCA for DERs is summarized Figure 1-1, which also shows where to find information and guidance on the BCA process in specific Parts or Appendices of this manual.

Figure 1-1. Process of Conducting BCA for DERs

Develop Primary BCA Test	Develop Secondary BCA Test(s)	Conduct/Implement BCA	Present BCA Results
• Identify applicable policy goals • Decide which benefits and costs to include in test • Refer to: ○ Parts I-II ○ Appendices A-F	• Decide which benefits and costs to include in any secondary test(s) • Decide how the secondary tests will be used • Refer to: ○ Parts I-II ○ Appendices A-F	• Determine values for each benefit and cost in test(s) • Determine which discount rate(s) to use • Conduct individual DER or multiple DER BCA • Refer to: ○ Parts III-IV ○ Appendices C, F, G, H	• Present test(s), values of benefits and costs, key assumptions • Present results • Refer to: ○ Parts I, II and IV ○ Appendices B and D

In addition to navigating this manual using Figure 1-1 above, below presents the organization of this document by major Parts, Chapters and Appendices, with a brief description of topics covered.

Users of this manual can refer to both Figure 1-1 and Table 1-2 to help navigate key sections or topics in this manual.

Table 1-2. Overview of the National Standard Practice Manual for DERs

Part/ Chapter	Topic	Description
Chapter 1	Introduction	Describes the purpose and scope of this manual, with an overview of BCA
Part I	**The NSPM Benefit-Cost Analysis Framework**	
Chapter 2	Benefit-Cost Analysis Principles	Describes fundamental BCA principles that serve as the foundation for remainder of this manual
Chapter 3	Developing BCA Tests	Provides guidance on how to develop a jurisdiction's primary cost-effectiveness test, and any secondary tests
Part II	**DER Benefits and Costs**	
Chapter 4	DER Benefits and Costs	Presents a catalog of the full range of benefits and costs that may be applicable to specific types of DERs
Chapter 5	Cross-Cutting Benefit and Cost Considerations	Discusses a variety of issues and considerations that span several of the benefits and costs listed in Chapter 4
Part III	**Specific DER Types – BCA Issues and Guidance**	
Chapter 6	Energy Efficiency Resources	These chapters describe and provide guidance on key factors that affect the benefits and costs relevant to specific DER technologies (EE, DR, DG, DS and Electrification)
Chapter 7	Demand Response Resources	
Chapter 8	Distributed Generation Resources	
Chapter 9	Distributed Storage Resources	
Chapter 10	Electrification	
Part IV	**Multiple DER Types – BCA Issues and Guidance**	
Chapter 11	Multiple On-Site DERs	Describes how to apply BCA principles and concepts to situations with multiple DER types per customer site, such as grid interactive efficient buildings
Chapter 12	Non-Wires Solutions	Describes how to apply BCA principles and concepts to situations with multiple DER types in a geographic region, such as non-wires solutions
Chapter 13	System-wide DER Portfolios	Describes how to apply BCA principles and concepts to situations with multiple DER types across a utility service territory
Chapter 14	Dynamic System Planning	Provides a brief overview of the key concepts of integrated distribution planning and integrated grid planning
Part V	**Appendices**	
Appendix A	Rate Impacts	Describes the difference between cost-effectiveness and rate impact analyses, and the role of rate, bill, and participation analyses
Appendix B	Template NSPM Tables	Tables that can be used by jurisdictions to document applicable policies and relevant benefits and costs to inform their BCA
Appendix C	Approaches to Accounting for Relevant Impacts	Provides guidance on options to account for relevant benefits and costs, including hard-to-quantify impacts and non-monetary impacts
Appendix D	Presenting BCA Results	Provides guidance on presenting results in a way that is most useful for making cost-effectiveness decisions
Appendix E	Traditional Cost-Effectiveness Tests	Summarizes the commonly used traditional cost-effectiveness tests from the *California Standard Practice Manual*
Appendix F	Transfer Payments and Offsetting Impacts	Provides guidance on impacts that appear to be both a benefit to one party and a cost to another party, thereby cancelling each other out
Appendix G	Discount Rates	Describes ways to determine discount rates that are consistent with the jurisdiction's applicable policy goals
Appendix H	Energy Efficiency—Additional Guidance	Describes how to address free-riders and spillover effects in cases for which net savings are used; and treatment of early replacement measures
References		

PART I: THE NSPM BENEFIT-COST ANALYSIS FRAMEWORK

Overview

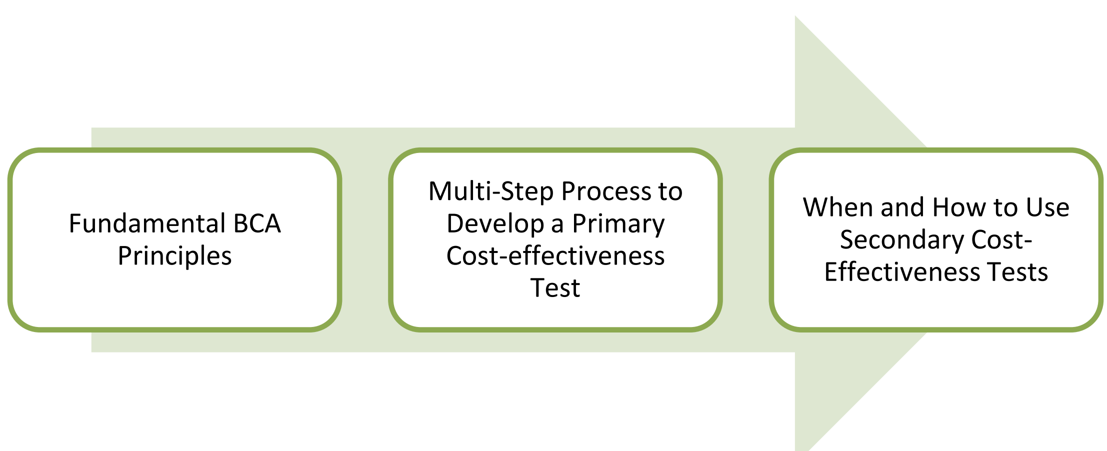
This part of the manual presents the NSPM BCA Framework that can be used by jurisdictions to assess the cost-effectiveness of DERs.

The NSPM BCA Framework is composed of the following three elements, as shown in Figure 1-2:

1. A set of **fundamental principles** that serve as the foundation for jurisdictions assessing the cost-effectiveness of potential DER investments in an economically sound and policy-neutral manner.
2. A **multi-step process** for developing a jurisdiction's primary test—a Jurisdiction-Specific Test (JST)—or reviewing whether or to what extent a jurisdiction's current test(s) aligns with the NSPM's fundamental principles.
3. Guidance on when and how to use **secondary tests** to (a) inform the prioritization of cost-effective DERs, as determined by a primary JST, and (b) consider marginally non-cost-effective DERs.

Chapter 2 introduces the fundamental principles that serve to guide BCA and inform development of a jurisdiction's primary cost-effectiveness test. Chapter 3 lays out a multi-step process for developing a jurisdiction's primary test and provides guidance on development and use of secondary tests. Part I also references other parts of the NSPM that describe a wide range of considerations and inputs for assessing the cost-effectiveness of specific, individual DERs or multiple DERs.

Figure 1-2. The NSPM Benefit-Cost Analysis Framework



2. BENEFIT-COST ANALYSIS PRINCIPLES

This chapter describes fundamental BCA principles that serve as the foundation for both developing a jurisdiction's primary test and applying the related guidance provided in other sections of the NSPM.

2.1 Summary of Key Points

- Principles are commonly adopted in industries to establish foundational standards by which an industry conducts its practice.
- The NSPM principles serve as a foundation for economically sound and policy-neutral BCA practice to use in the assessment of DER investments.
- The NSPM principles can guide the selection of relevant benefits and costs for a jurisdiction to include in its primary test, as well as any secondary cost-effectiveness tests.
- The NSPM principles can also be used to guide the application of cost-effectiveness testing, selection of a discount rate, and the reporting of the BCA results.
- The NSPM principles can inform the process for choosing and prioritizing DERs to be implemented.

2.2 The Importance of Principles

Principles are commonly adopted in industries to establish foundational standards by which an industry conducts its practice, such as in the fields of accounting, economics, medical practice, and psychology. For example, utility regulators have used the Bonbright Principles for utility ratemaking purposes for decades (Bonbright 1961).

Principles help to guide sound practice and support more efficient decision-making, in particular when applied to the analysis of new situations. When a set of foundational principles is understood, accepted, and applied in an industry, the principles support the decision-makers in making decisions in a clear, transparent, and efficient manner.

2.3 The NSPM Principles

The NSPM principles defined in this manual serve as a foundation for conducting DER BCAs. Developed and informed by DER industry stakeholders,[4] the NSPM principles are intended to be policy-neutral,[5]

[4] DER industry stakeholders include those on the NSPM Advisory Group listed on the Acknowledgements page.

[5] The NSPM is policy-neutral in that it can be used by any jurisdiction, regardless of what policies it has adopted. The manual does not advocate or reject any specific policies but rather sets forth that a jurisdiction's cost-effectiveness practices should align with the jurisdiction's policy goals and objectives.

technology-neutral, and in line with sound economic practices. They are foundational in guiding regulators and others in the assessment of DER cost-effectiveness.

The NSPM principles in and of themselves do not determine what is a jurisdiction's appropriate cost-effectiveness test for DERs. The NSPM principles are intended to be applied in a manner that takes into consideration the characteristics and circumstances of each jurisdiction's approach to energy resources and can result in different JSTs for different jurisdictions.

The NSPM principles provide a construct to guide jurisdictions in their review of *existing* cost-effectiveness practice by testing for alignment with the principles and determining where modifications may be needed to improve alignment. Alternatively, the principles can be applied in developing a *new* primary cost-effectiveness test from the ground up.

The NSPM principles are summarized in Table 2-1 and discussed in the following text. In applying the principles, it is important to note that:

- The NSPM principles are not mutually exclusive as they contain some overlapping concepts; and
- It is up to the users of the NSPM to decide if they will adhere to all the principles in all situations or, for example, if it is necessary to make tradeoffs between certain principles in certain situations.

Table 2-1. Fundamental NSPM BCA Principles

Principle 1	**Treat DERs as a Utility System Resource** DERs are one of many energy resources that can be deployed to meet utility/power system needs. DERs should therefore be compared with other energy resources, including other DERs, using consistent methods and assumptions to avoid bias across resource investment decisions.
Principle 2	**Align with Policy Goals** Jurisdictions invest in or support energy resources to meet a variety of goals and objectives. The primary cost-effectiveness test should therefore reflect this intent by accounting for the jurisdiction's applicable policy goals and objectives.
Principle 3	**Ensure Symmetry** Asymmetrical treatment of benefits and costs associated with a resource can lead to a biased assessment of the resource. To avoid such bias, benefits and costs should be treated symmetrically for any given type of impact.
Principle 4	**Account for Relevant, Material Impacts** Cost-effectiveness tests should include all relevant (according to applicable policy goals), material impacts including those that are difficult to quantify or monetize.
Principle 5	**Conduct Forward-Looking, Long-term, Incremental Analyses** Cost-effectiveness analyses should be forward-looking, long-term, and incremental to what would have occurred absent the DER. This helps ensure that the resource in question is properly compared with alternatives.
Principle 6	**Avoid Double-Counting Impacts** Cost-effectiveness analyses present a risk of double-counting of benefits and/or costs. All impacts should therefore be clearly defined and valued to avoid double-counting.
Principle 7	**Ensure Transparency** Transparency helps to ensure engagement and trust in the BCA process and decisions. BCA practices should therefore be transparent, where all relevant assumptions, methodologies, and results are clearly documented and available for stakeholder review and input.
Principle 8	**Conduct BCAs Separately from Rate Impact Analyses** Cost-effectiveness analyses answer fundamentally different questions than rate impact analyses. Cost-effectiveness analyses should therefore be conducted separately from rate impact analyses.

PRINCIPLE 1 TREAT DERS AS A UTILITY SYSTEM RESOURCE

DERs are resources that can be used to defer or avoid spending on traditional utility distribution, transmission, and/or generation resources. DERs are also used for increasing reliability, improving power quality, distribution balancing, or enabling the addition of renewables onto the grid. As such, if a utility or other entity is supporting a DER(s)—such as through a direct incentive, time-of-use (TOU) rate, or net metering tariff—and regardless of whether it owns or controls the DER(s), the BCA should ensure consistent treatment with other DERs and resources, including use of consistent cost-effectiveness principles, methodologies, and assumptions. Absent consistent assessment, utilities risk supporting certain resources over others, resulting in potential increased costs for utility customers and missed opportunities for achieving applicable policy goals.

> Absent consistent BCA assessment, utilities risk over-investing in some resources while under-investing in others, resulting in potential increased costs for utility customers and missed opportunities for achieving applicable policy goals.

This principle necessitates that the full range of utility system impacts serve as the foundation of a jurisdiction's primary cost-effectiveness test, upon which other (non-utility system) impacts may be added where applicable to relevant policy goals (per the *Align with Policy Goals* principle). Refer to STEP 2 in Chapter 3 for guidance on applying this principle, and Chapter 4 for a description of utility system impacts.

PRINCIPLE 2 ALIGN WITH POLICY GOALS

Utilities and others often invest in or otherwise support DERs to meet a variety of goals, including policy goals. As such, a jurisdiction's primary cost-effectiveness test should account for the jurisdiction's applicable policy goals. The choice of investments in DERs and other utility resources can materially affect the costs, timeframe, and ability to achieve policy goals. Thus, cost-effectiveness analyses should inform and guide resource choices in that context to ensure alignment with established policies.

Regulators typically have broad statutory authority to set rates that are fair, just, and reasonable; ensure that utilities provide customers with safe and reliable services; ensure a fair and reasonable return on equity; and generally, guide utility actions that are in the public interest. Regulators also typically operate in the context of other relevant jurisdictional policies, some of which affect the implementation of DERs.

Energy and other applicable policy goals evolve over time, responding to changes in the energy industries and society, as well as changing perspectives from policymakers, regulators, utilities, and other industry stakeholders. As such, identifying applicable policies for a jurisdiction is not a static process, but one that should be periodically updated to reflect evolving policy priorities. Therefore, a jurisdiction's cost-effectiveness test(s) may need to periodically evolve as well.

> Policy goals can be articulated in many different ways, including but not limited to legislation; executive orders; regulations; commission or board guidelines, standards, or orders; a utility's resource planning principles and policies; and requirements of other governing agencies within a jurisdiction.

In some cases, a jurisdiction may have different policy goals for different DER types.[6] STEP 1 in Chapter 3 and Chapter 13 provide guidance for how jurisdictions can analyze DER types as consistently as possible even if different goals exist. Appendix B provides template tables that regulators, utilities, and others can use to take inventory of their applicable policy goals and associated relevant impacts.

PRINCIPLE 3 ENSURE SYMMETRY

Symmetrical treatment in the accounting of benefits and costs is necessary to avoid bias toward any one resource, whereby both benefits and costs are included (or both excluded) for each relevant type of impact.

For example, accounting for utility system impacts should ensure that the full range of utility system benefits and costs be included in the cost-effectiveness analysis. Similarly, to the extent that accounting for host customer impacts and any societal impacts are relevant to a jurisdiction (per its articulated applicable policies, as provided by the *Align with Policy Goals* principle), then both the benefits and costs should be accounted for. If a jurisdiction's applicable policy goals *do not dictate* that DER host customer impacts be accounted for, or are silent on this treatment, then regulators can determine with stakeholder input whether to include host customer impacts, as long as the treatment for the costs and the benefits is consistent and symmetric.

If host customer costs are included in the test, then host customer benefits should also be included (even if certain impacts are hard to quantify and monetize, per the *Account for Relevant, Material Impacts* principle below.) Conversely, the *Ensure Symmetry* principle holds that if a jurisdiction decides not to account for any material host customer benefits, then it should not include any host customer costs.

If each type of impact is not treated symmetrically, the result will be a sub-optimal selection of resources, where the BCA test will result in bias in favor of or against DERs. This will lead to higher than necessary costs imposed upon utility customers and missed opportunities to achieve policy goals.

Ensuring the symmetrical treatment of impacts for both utility and non-utility system impacts is further discussed and illustrated in Chapter 3: STEP 4.

> If a jurisdiction's applicable policy goals *do not dictate* that DER host customer impacts be accounted for, or are silent on this treatment, then regulators can determine with stakeholder input whether to include host customer benefits and costs, as long as the treatment for the costs and the benefits is consistent and symmetric.

PRINCIPLE 4 ACCOUNT FOR RELEVANT, MATERIAL IMPACTS

Those DER impacts that are deemed to be relevant and material should be accounted for in cost-effectiveness tests. The relevant, material impacts should ideally be estimated in monetary terms so that they can be put into useful BCA metrics, such as the present value of revenue requirements, net benefits, and benefit-cost ratios.

As with many utility system resources, some DER benefits and costs are challenging to quantify and monetize. Data may not be readily available, studies to establish values may require a considerable amount of time and/or resources to conduct, and such studies might still result in significant

[6] Where jurisdictions currently evaluate different DER types using different cost-effectiveness tests or assumptions, it is usually because their BCA practices were developed in different contexts (e.g., different utility commission dockets) without a uniform approach—not because there are any inherent reasons for using different tests for different DERs.

Relevant impacts are those defined by utility system benefits and costs (according to the *Treat DERs as a Utility System Resource* principle), and any non-utility system impacts identified based on applicable policy goals (the *Align with Policy Goals* principle).

Material impacts are those that are expected to be of sufficient magnitude to affect the result of a BCA. If an impact is determined to be immaterial, it should be noted in the BCA.

uncertainty. Similarly, there may be cases where some impacts are not counted at all because they are not properly identified, understood, or valued.

Nonetheless, DER benefits and costs that are relevant and are expected to be material should be accounted for even if they are difficult to quantify and monetize. There are a variety of ways to account for some impacts without necessarily monetizing them—such as the use of proxies, use of values from other jurisdictions where applicable, or use of alternative thresholds. Accounting for hard-to-quantify impacts qualitatively is another approach to consider. (See Chapter 3: STEP 3 and Appendix C.) In general, any benefit or cost value used in DER BCAs should be based on a logical, documented, justified method and should not be arbitrary or contrived.

When deciding whether to include a benefit or cost in a BCA test, it is important to distinguish between the definition of the BCA test and the application of the test. Any impact that is deemed to be relevant (as identified by applying Principles 1-3) should be included as part of the definition of the BCA test. In some cases, a benefit or cost may be relevant but not material, and therefore would not need to be included in the application of the BCA test. In this case, the impact is included in the definition of the BCA test but is not included in the application of it. This distinction is especially important when using the same BCA test across multiple DER types and when using the same test over many years.

Using best available information to approximate hard-to-quantify impacts, or accounting for impacts qualitatively, is preferable to assuming that those benefits or costs do not exist or have no value.

For example, ancillary services are utility system impacts that are material for some DER types, but not others. Therefore they should be included in the *definition* of any BCA test. If a jurisdiction deems that the impacts of a DER on ancillary services are immaterial, the impacts should be set to zero in the application of the BCA test. Ancillary services are thus included in the *definition* of the BCA test but not in the *application* of the test for that DER. If a DER's ancillary services impacts are material, then the impacts should be included in the *application* of the test. This further allows for potential changes in impacts for a particular DER over time.

PRINCIPLE 5 CONDUCT FORWARD-LOOKING, LONG-TERM, INCREMENTAL ANALYSES

Cost-effectiveness analysis of DERs should be forward-looking, capturing the difference between benefits and costs that would occur over the life of the DERs and those that would occur absent the implementation of the DERs.

This principle embodies three inter-related concepts:

- *Forward-looking impacts:* BCAs should include only forward-looking impacts because historical costs, also known as sunk costs, cannot be changed and will remain in place under any

The term *long-run* refers to the period covering the full life cycle of the resource being analyzed, i.e., for a period of time sufficient to capture the full stream of benefits and costs associated with the resources under analysis.

future scenario. Therefore, historical costs are not relevant when comparing future DER implementation scenarios.[7]

- *Long-run benefits and costs:* BCAs should have a study period that is long enough to include long-run benefits and costs of DERs. This approach is necessary to account for the full benefits and costs of the DER being evaluated, particularly since energy resources, including many DERs and their alternatives, can last decades and thus resource decisions made today can affect costs and benefits far into the future.
- *Incremental impacts:* BCAs should consider only incremental impacts, i.e., the changes that will occur because of the DERs, relative to a scenario where the DERs are not in place. This concept is applicable to both benefits and costs.

This principle is consistent with utilities having a responsibility to meet utility customer needs in a safe, reliable, and least-cost way over the long term, as well as regulators having a responsibility to protect customers over both the short term and the long term. Over-emphasis on short-term costs may lead to an increase in long-term costs for customers.

PRINCIPLE 6 AVOID DOUBLE-COUNTING IMPACTS

When defining and estimating the values of different DER impacts, it is important to recognize the potential for overlap between some impacts to avoid counting any of them more than once. In particular, caution is required to ensure that costs included in the cost-effectiveness test are not somehow captured in the benefits included in the test, and vice versa. Examples of such overlaps are:

- Utility system risk impacts might overlap with other utility system impacts such as avoided generation costs;
- Costs for complying with environmental regulations might overlap with societal environmental costs; and
- Public health impacts might overlap with either host customer health and safety impacts or societal environmental costs.

Chapter 4 further identifies areas of potential overlap across impacts.

PRINCIPLE 7 ENSURE TRANSPARENCY

DER BCAs require many detailed assumptions and methodologies, and they typically produce detailed results. For regulators, utilities, and other stakeholders to properly assess and understand BCAs—and therefore to ultimately ensure that BCA conclusions are reasonable and robust—key inputs, assumptions, methodologies, and results should be clearly documented in sufficient detail.

Transparent documentation helps to ensure that the approach to cost-effectiveness analysis is consistent with fundamental principles, regulatory objectives, and applicable policy goals. It also facilitates and expedites regulatory and stakeholder understanding and review of cost-effectiveness analyses.

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[7] Historical costs do have important implications for rate impacts and potential cost-shifting between customers. These costs should be considered in a separate rate impact analysis. (See Appendix A.)

Transparency also entails ensuring that stakeholder input allows for review and discussion of the BCA assumptions, methods, and results.

Chapter 3: STEP 5 provides guidance on applying the *Ensure Transparency* principle, with Appendix B and Appendix D presenting template tables for documenting applicable goals, identifying relevant impacts, and presenting BCA results.

PRINCIPLE 8 CONDUCT BCAS SEPARATELY FROM RATE IMPACT ANALYSES

This manual focuses on determining the cost-effectiveness of resource investments. However, many jurisdictions are concerned about rate impacts and this concern is often raised in the context of cost-effectiveness analyses.

DERs, like all energy resources, can affect customer rates. Some DERs are likely to increase rates, while other DERs are more likely to reduce rates. Some DERs might have little effect on rates at all. The extent to which DERs will impact rates depends upon many factors, including the deployment of the DERs, the extent to which they reduce or increase utility system costs, the extent to which they provide utility system benefits, and the extent to which they reduce or increase utility sales.

> Cost-effectiveness analyses and rate impact analyses serve different purposes, and it is important to delineate and understand the differences to ensure that the different types of analyses provide meaningful information for DER decision-making.

Cost-effectiveness analyses and rate impact analyses serve different purposes, and it is important to delineate and understand the differences between them to ensure that they both provide meaningful information for DER decision-making. Specifically, these different analyses answer fundamentally different questions:

- Benefit-cost analyses answer the question: *Which DERs are expected to provide benefits that exceed costs for all customers on average?*
- Rate impact analyses answer the question: *How much will DERs increase or decrease customer rates, and if so by how much?*

Another key difference between BCAs and rate impact analyses has to do with how the impacts are distributed across customers. While BCAs indicate the extent to which DERs will provide net benefits to customers on average (regardless of how the benefits and costs are distributed across different customers), rate impact analyses indicate how DERs will affect customer rates and therefore any distributional and equity issues created by DERs.

The Rate Impact Measure (RIM) test is one of the traditional cost-effectiveness tests that has been used to assess the rate impacts of DERs. However, because the RIM Test accounts for historical, sunk costs, and is not based on a forward-looking, incremental analysis, the information it provides is of limited value for informing resource investment decisions (see Appendix A). The RIM Test can be used simply to determine whether a DER is likely to increase or reduce rates, and/or to determine whether a rate impact analysis is needed to better understand equity concerns. For example, if the results of the RIM Test are positive or suggest that the rate impacts might be small (e.g., with a benefit-cost ratio of 0.95), then regulators and other stakeholders might decide that there is no need for a rate impact analysis. If the results of the RIM test are much lower, then regulators and utilities might decide to look into rate impacts and equity issues further.

If a jurisdiction decides that a rate impact analysis is warranted, then it is important to conduct a separate long-term rate impact analysis, which includes a bill and participation analysis as well. These analyses address different equity issues:

- *Rate impacts* indicate the extent to which rates for all customers might increase or decrease due to DERs.
- *Bill impacts* indicate the extent to which customer bills might be affected by DERs, both for host customers and other customers.
- *Participation impacts* indicate the portions of customers that will experience bill reductions or bill increases.

Taken together, these three factors indicate the distributional impact on customers from DERs, and therefore the extent to which DERs might lead to equity concerns. It is critical to estimate the rate, bill and participant impacts properly, and to present them in terms that are meaningful for considering distributional equity issues. (See Appendix A.)

Further, while BCAs and rate, bill, and participation analyses should be conducted separately, such analyses should be conducted within a common docket or proceeding to help provide a comprehensive assessment of both cost-effectiveness and equity issues.

3. DEVELOPING BENEFIT-COST ANALYSIS TESTS

This chapter describes provides guidance on how to develop a jurisdiction's primary cost-effectiveness test, the Jurisdiction-Specific Test (JST), as well as any complementary secondary tests to help inform resource investment decisions.

3.1 Summary of Key Points

- A policy-neutral and systematic multi-step process can be used to develop a jurisdiction's primary test for assessing DERs, referred to as the Jurisdiction-Specific Test.
- The JST should be based on the regulatory perspective, the perspective of those that oversee utility DER investment decisions, as guided by a jurisdiction's applicable policy goals. This stands in contrast to traditional cost-effectiveness tests that were not necessarily designed to take this regulatory perspective or applicable policy goals into account.
- The JST used to evaluate DERs answers the fundamental question: Which DERs have benefits that exceed costs and therefore merit acquisition or support from utilities or others?
- Secondary cost-effectiveness tests can be used to provide additional information, represent different perspectives, and answer different questions.

3.2 Cost-Effectiveness Testing Perspectives

3.2.1 Traditional Perspectives

The cost-effectiveness tests traditionally used to evaluate DERs to date consider benefits and costs from different perspectives, and therefore answer different cost-effectiveness questions. The perspectives of the traditional tests, as provided in the 2001 *California Standard Practice Manual* are as follows (See Appendix E):

- *Utility Cost Test (UCT),* also known as *the Program Administrator Cost Test (PACT),* which includes the benefits and costs experienced by the utility system.
- *Total Resource Cost (TRC) Test*, which includes the benefits and costs experienced by the utility system, plus benefits and costs to host customers.
- *Societal Cost Test (SCT)*, which includes the benefits and costs experienced by society.
- *Participant Cost Test (PCT)*, which includes the benefits and costs experienced by host customers. This test supports program design and host customer investment decisions.

- *Rate Impact Measure (RIM) Test*, which indicates whether rates are likely to increase or decrease as a result of DER investments, and therefore primarily represents the perspective of non-host customers.

Over the years, most states have adopted variations of the UCT, SCT, and TRC Test for cost-effectiveness testing, primarily for EE resources. In most cases, these tests in their adopted forms do not adhere to the theoretical definitions of the traditional tests (e.g., such as state use of a modified TRC test) (NESP 2019). In addition, the traditional tests generally do not utilize the perspective of regulators and other decision-makers that are responsible for reviewing DER investment decisions to ensure that they provide net benefits and meet applicable policy goals.[8]

An objective of the NSPM is to support jurisdictions' review of their traditional test practices by applying the NSPM principles and determining the extent of alignment with the principles. This process can help to identify specific modifications or refinements to current BCA practice to improve alignment or can inform the development of a new primary test—a jurisdiction-specific test – that is unique to the jurisdiction.

3.2.2 The Regulatory Perspective

This manual presents the regulatory perspective, which refers to the perspective of regulators or similar entities that oversee utility DER investment decisions. This perspective is guided by the jurisdiction's applicable policy goals and objectives—whether in laws, regulations, organizational policies, or other codified forms in which utilities or energy providers operate. As such, the regulatory perspective reflects the *Align with Policy Goals* principle.

The regulatory perspective is typically broader than the utility perspective, in that it accounts for applicable policy goals (beyond the basic utility goals of providing affordable, safe, reliable electricity services). The regulatory perspective may be narrower than the societal perspective, in that it may not account for some societal impacts if not articulated in statute, regulatory decisions, or other governing policy documents.

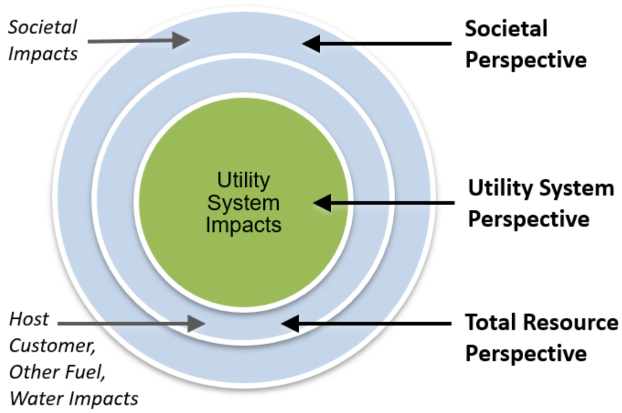
The regulatory perspective reflects the utility system perspective plus the values of the jurisdiction's relevant policy goals and objectives. The regulatory perspective could theoretically align with a traditional test perspective, though is more likely to be unique to that jurisdiction. Figure 3-1 illustrates the regulatory perspective relative to the perspectives underlying the traditional cost tests.

The regulatory perspective reflects a jurisdiction's applicable goals that can be articulated in different ways, including but not limited to: legislation; executive orders; regulations; commission or board guidelines, standards or orders; utility resource planning principles and policies; and requirements of other jurisdictional governing agencies.

[8] The *California Standard Practice Manual* explicitly notes that policy goals are an "integral" part of cost-effectiveness analyses, but that it does not address policy goals: "The implementing agencies… have traditionally utilized open public processes to incorporate the diverse views of stakeholders before adopting externality values and policy rules which are an integral part of the cost-effectiveness evaluation. These policy rules are not a part of this manual" (CA PUC 2001, page 6). The NSPM BCA Framework differs in that it sets forth the principle that policy goals should be accounted for in determining the primary test for cost-effectiveness analyses.

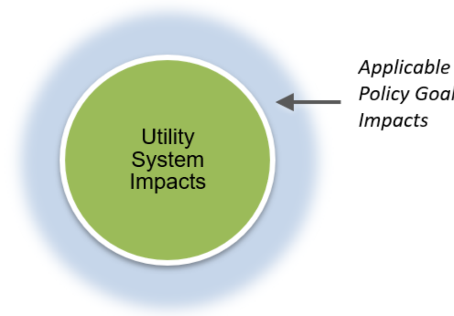
Figure 3-1. Cost-Effectiveness Testing Perspectives

Traditional Perspectives



- Three perspectives define the scope of impacts to include in the most common traditional cost-effectiveness tests.

Regulatory Perspective



- Perspective of public utility commissions, legislators, muni/coop boards, public power authorities, and other relevant decision-makers.
- Accounts for utility system plus impacts relevant to a jurisdiction’s applicable policy goals (which may or may not include host customer impacts).
- Can align with one of the traditional test perspectives, but not necessarily.

The regulatory perspective is necessary to ensure that a jurisdiction’s relevant policy goals are considered in its cost-effectiveness test in order to avoid sub-optimal resource selections with respect to stated goals. Otherwise the jurisdiction might incur additional costs to meet its policy goals.

3.3 Developing a Jurisdiction-Specific Test

Developing a jurisdiction’s primary cost-effectiveness test—the JST—is foundational to the BCA process.

Table 3-1 presents the key steps to developing a jurisdiction’s primary test. The following subsections describe each of these steps in more detail. Further information on implementing BCA tests is presented in Chapters 6–14, and examples of reporting BCA results are presented in Appendix D.

Because the primary test is based upon each jurisdiction’s applicable policy goals, and those goals can vary across jurisdictions, the JST may take a variety of forms across jurisdictions. This outcome can have the disadvantage of making it difficult to compare BCA results across jurisdictions absent sufficient transparency and information. Yet, it has the advantage of allowing each jurisdiction to tailor its primary test to reflect its own goals and objectives.

> A jurisdiction’s primary test—the Jurisdiction Specific Test—should reflect the regulatory perspective to ensure proper accounting of the full range of utility system impacts and reflect the jurisdiction’s applicable policy goals. Such a primary test can be used to answer the critical question: *Which DERs have benefits that exceed costs and therefore merit utility acquisition or support on behalf of customers*?

Table 3-1. Developing a Jurisdiction's Primary Test: A 5-Step Process

STEP 1	**Articulate Applicable Policy Goals** Articulate the jurisdiction's applicable policy goals related to DERs.
STEP 2	**Include All Utility System Impacts** Identify and include the full range of utility system impacts in the primary test, and all BCA tests.
STEP 3	**Decide Which Non-Utility System Impacts to Include** Identify those non-utility system impacts to include in the primary test based on applicable policy goals identified in Step 1: • Determine whether to include host customer impacts, low-income impacts, other fuel and water impacts, and/or societal impacts.
STEP 4	**Ensure that Benefits and Costs are Properly Addressed** Ensure that the impacts identified in Steps 2 and 3 are properly addressed, where: • Benefits and costs are treated symmetrically. • Relevant and material impacts are included, even if hard to quantify. • Benefits and costs are not double-counted. • Benefits and costs are treated consistently across DER types.
STEP 5	**Establish Comprehensive, Transparent Documentation** Establish comprehensive, transparent documentation and reporting, whereby: • The process used to determine the primary test is fully documented. • Reporting requirements and/or use of templates for presenting assumptions and results are developed.

Note: The 5-step process is not necessarily chronological in order and often requires iteration.

STEP 1 ARTICULATE APPLICABLE POLICY GOALS

This first step applies the *Align with Policy Goals* principle, which states that a jurisdiction's primary cost-effectiveness test should account for applicable policy goals. Documenting applicable goals at the outset of either developing a JST or reviewing current BCA tests and practices is necessary to ensure that the cost-effectiveness test explicitly and properly accounts for such goals, and therefore the jurisdiction's regulatory perspective.

Policies typically take the form of mandates or objectives.

- *Policy Mandates:* Policy goals can include specific mandates for investing in or supporting DERs. For example, legislation might require utilities to achieve a certain amount of efficiency savings or distributed generation capacity by a specific year. In these cases, legislators have determined (or presumed) that the benefits associated with their policy directive exceed the costs. In these cases, utilities need to comply with the mandate, provided that a funding mechanism is available. Nonetheless, regulators and others may conduct BCAs for statutorily required DERs to (a) select the most cost-effective DERs within the statutorily mandated requirements by comparing the cost-effectiveness of different DERs and different implementation approaches; and (b) identify ways to reduce costs and increase benefits of those resources.

- *Policy Objectives:* Policy goals can be specific about meeting certain objectives without identifying how they should be met. For example, a jurisdiction might have a policy goal of increasing demand flexibility or serving low- and moderate-income customers, without specifying any particular technology or way to meet the goal. In these cases, BCAs should identify the most cost-effective resources for achieving the goal by comparing the attributes, including cost-effectiveness, of the different resources being evaluated to meet the intended objectives.

Examples of energy and non-energy related policy goals that may be applicable in some jurisdictions are provided in Table 3-2.[9]

Table 3-2. Examples of Policy Goals

Common Overarching Goals: Provide safe, reliable, reasonably priced electricity and gas services; support fair and equitable economic returns for utilities; promote customer equity; protect/reduce energy burden for low-income and vulnerable customers.
Resource Goals: Reduce electricity and gas system costs; develop least-cost energy resources; improve system reliability and resiliency; reduce system risk; promote resource diversity; increase energy independence; reduce price volatility; provide demand flexibility.
Other Applicable Goals: Ensure stable energy markets; reduce environmental impact of energy consumption; promote jobs and local economic development; improve health associated with reduced air emissions and better indoor air quality.

Non-utility system impacts should be included *only if consistent with achieving applicable policy goals.* In such cases, policy goals may be very general. For example, a jurisdiction might have policy goals to reduce low-income energy burdens, enhance local economic development, or reduce greenhouse gas (GHG) emissions, without specific utility system targets or requirements for each goal. Whether to include such general policy goals may be up to interpretation by regulators, and any such decisions should be informed by meaningful stakeholder input. Metrics can be used to indicate how well policy goals are being achieved, and the contribution of each DER to achieving those goals.

In some cases, it may be challenging to identify and articulate a jurisdiction's applicable DER policy goals, such as when jurisdictions have different policy goals for different DER types, making it difficult to establish a single primary test for all DER types. In these cases, there are several approaches for determining which policy goals to account for in the primary DER test (see STEP 4 and Section 3.5.)

Finally, the decision on how best to align policy objectives consistently across multiple DER analyses could have significant implications for the primary DER test and the DER assessments. Stakeholder input can help to inform the regulator's determination of the most appropriate approach (see STEP 5.)

[9] This list is not intended to be exhaustive, nor is it intended to imply a recommendation of any policies for any jurisdiction. It is intended to illustrate the types of policies that jurisdictions typically establish.

STEP 2 INCLUDE ALL UTILITY SYSTEM IMPACTS

This step of including all the utility system impacts in a JST applies the *Treat DERs as a Utility System Resource* principle, which sets forth that DERs be compared consistently with other utility resources. This emphasis on utility system impacts is important because these are the impacts that directly affect the utility customers that are supporting utility-sponsored DERs in one form or another. Including the utility system impacts in a cost-effectiveness test ensures that the test will, at a minimum, indicate the extent to which total utility system costs will be reduced (or increased) by the DER.

Utility system benefits and costs provide the foundation for every JST.

- The term "utility system" here is used to represent the entire energy system that provides services to retail customers.
- The three most historically applied cost-effectiveness tests, the UCT, the TRC, and the SCT, all include all utility system impacts, at a minimum.

This step requires accounting for all utility system impacts that will be affected by the DER. Specifically:

- For electric utilities, utility system impacts include the generation, transmission, and distribution of electricity services.
- For gas utilities, utility system impacts include the transportation, storage, and distribution of gas services.

Utility system impacts should be accounted for irrespective of the type of utility structure (e.g., investor-owned or publicly owned utilities) or market structure. In particular, for a jurisdiction with competitive wholesale markets and distribution-only electric utilities, it is important to account for the impacts on generation, transmission, and distribution because all these services will be affected by the DER and distribution customers have to pay for all those services—even if the utility funding or supporting the DER provides only distribution services.[10] Utility system impacts are generally defined as follows:

- *Utility system benefits* typically include all the utility system costs that would be avoided or deferred by implementing the DER. These avoided costs are one of the more important and sometimes challenging inputs to any BCA of DERs and will significantly affect the results of the analyses. Therefore, it is essential to ensure that avoided cost estimates are comprehensive, up to date, informed by stakeholders, and ultimately reviewed and approved by regulators or other decision-makers.
- *Utility system costs* typically include the portion of the DER paid by the utility, other financial or technical support provided to host customers, and interconnection costs and distribution system upgrades not paid by the DER owner. These costs also generally include any other utility system costs associated with DER implementation, administration, marketing, evaluation, measurement, and verification.

Accounting for Policies that affect Utility System Impacts: As an example, consider a jurisdiction that has a policy goal of reducing GHG emissions from the utility sector by 30% by 2030. Utilities are going to have to incur costs to meet that goal with or without the use of DERs. In this case, the cost of achieving this policy goal, and the associated benefits, are considered utility system impacts and should be included in the JST. See STEP 2 for further guidance.

[10] Additionally, it is important that the avoided cost impact assessment of the BCA be aligned with utility planning assumptions in order to be consistent with "actual" avoided costs. For example, if the BCA uses one method to calculate capacity reduction needs, but the utility uses another method and calculates a different value, the BCA will either over- or under-estimate what the utilities actual avoided costs end up being (which is dependent on the utility's specific planning and operational practices).

See Chapter 4 for descriptions of DER benefits and costs within each of these categories, and Chapter 5 for discussion of cross-cutting considerations and factors that can affect the magnitude of impacts.

STEP 3 DECIDE WHICH NON-UTILITY SYSTEM IMPACTS TO INCLUDE

This step applies the *Align with Policy Goals* principle, which sets forth that a JST should account for applicable policy goals. Once a jurisdiction's applicable policies have been identified and articulated in STEP 1, and utility system benefits and costs are identified and accounted for in STEP 2, this next step involves deciding which non-utility benefits and costs to include in the test, based on applicable policy goals. These non-utility impacts can be categorized as host customer impacts and societal impacts.

In some cases, the determination of whether to include certain non-utility system impacts is fairly straightforward. For example, legislation establishing a specific DER program might explicitly state that the goals of the program are to create jobs and improve public health. Or a state might have statutory language requiring them to consider impacts such as environmental benefits in resource decision-making. In other cases, the determination may be less clear. This is often the case regarding host customer benefits and costs, where policies do not necessarily articulate whether they should be accounted for in a primary cost-effectiveness test. The decision of which non-utility system impacts should be included in a JST, in order to reflect policy goals, will need to be made by regulators with appropriate input from stakeholders.

Table 3-3 presents an illustrative list of non-utility impacts that could be included in a primary test to the extent they are relevant to a jurisdiction. See Chapter 4 for descriptions of DER benefits and costs within each of these categories, and Chapter 5 for discussion of cross-cutting considerations and factors that can affect the magnitude of impacts.

Table 3-3. Commonly Considered Non-Utility System Impacts

Non-Utility Impact	Description
Other fuel impacts	Impacts on fuels that are not provided by the relevant utility, for example, electricity (for a gas utility), gas (for an electric utility), oil, propane, gasoline, and wood
Host customer impacts	Host customer portion of DER costs and host customer non-energy impacts (NEI), such as impacts on productivity, comfort, health and safety, mobility, and more
Impacts on low-income customers	Impacts that are different from or incremental to non-low-income customer impacts such as energy affordability and poverty alleviation
Environmental impacts	Impacts associated with GHG emissions, criteria pollutant emissions, land use, solid waste, etc.; includes only those impacts not embedded in the utility cost of compliance with environmental regulations, which should always be treated as a utility system cost
Public health impacts	Impacts on public health; includes health impacts that are not included in host customer impacts or environmental impacts and includes benefits in terms of reduced healthcare costs
Economic development and jobs	Impacts on direct and indirect economic development and jobs
Energy security	Reduced reliance on fuel or energy imports from outside the state, region, or country

This table is presented for illustrative purposes and is not meant to be an exhaustive list or applicable in every jurisdiction.

STEP 4 ENSURE THAT BENEFITS AND COSTS ARE PROPERLY ADDRESSED

STEP 4 in developing a jurisdiction's primary test involves ensuring that the impacts identified in STEP 2 and STEP 3 are properly addressed, whereby:

- Benefits and costs are treated symmetrically;
- Relevant and material impacts are included, even if hard to quantify;
- Benefits and costs are not double-counted; and
- Benefits and costs are treated consistently across DER types.

Benefits and Costs are Treated Symmetrically

The *Ensure Symmetry* principle in Chapter 2 sets forth that cost-effectiveness practices be symmetrical, where both benefits and costs are included (or in some cases may be excluded) for each relevant type of impact. This principle applies to different categories of impacts as follows:

- *Utility System Impacts:* If the full range of utility system costs are included, then the full range of utility system benefits should be included in the cost-effectiveness analysis, even if hard to quantify (consistent with the *Account for Relevant, Material Impacts* principle).
- *Host (participant) customer impacts:* If regulators and others have decided to account for host customer impacts in the jurisdiction's primary BCA test (per its articulated applicable policies, as provided by the *Align with Policy Goals* principle) then both costs and benefits experienced by those customers should be included in the test. On the cost side, this would most commonly be the host customer portion of the DER installation costs. On the benefits side, depending on the resource, there may be a variety of non-energy benefits experienced by the host customer (e.g., improved reliability, improved comfort, improved productivity, etc.). If regulators and others are reluctant to include any or some portion of the material host customer benefits in the BCA, then the host customer costs should be treated consistently (see example below.)
- *Other non-utility system impacts:* If a jurisdiction's applicable policies indicate that a certain category of costs should be included in its cost-effectiveness test (e.g., other fuel, water, low income, environmental, public health, economic development) then the comparable benefits for that category should be captured in the test as well, and vice versa.

Example: Ensuring Symmetry in the Treatment of Host Customer Benefits and Costs

The *Ensure Symmetry* principle provides that benefits and costs should be accounted for symmetrically in BCAs, whether relevant to utility system or non-utility system impacts. The following example illustrates the importance of this principle, and how treatment of host customer impacts can affect the BCA results of a DER.

In this example, it costs a total of $9,000 to install a DER measure at a host customer site, comprised of total measure cost ($7,500) and utility administrative cost ($1,500). The host customer pays the DER cost ($5,625), which complements the utility incentive ($1,875). The host customer is expected to experience non-energy benefits ($4,000).*

In Scenario A, the BCA accounts for the host customer costs ($5,625), but not the host customer benefits ($4,000). This asymmetrical treatment of costs and benefits suggest the program is not cost-effective, with a BCA of 0.67. Yet this scenario fails to recognize the non-energy related benefits to the host customer (e.g., increased comfort, reduced indoor air pollution, increased asset value, etc.).

In Scenario B, symmetry is achieved by including both the host customer costs and benefits. In this case, a jurisdiction has conducted analyses to estimate monetary values of the non-energy benefits (see Appendix C). This symmetrical treatment suggests the program is cost-effective with a BCA ratio of 1.11.

In Scenario C, neither host customer costs nor benefits are included in the BCA. The scenario assumes that the jurisdiction has decided to not include host customer impacts in its primary test. If a jurisdiction is reticent to quantify host customer benefits, then exclusion of both costs and benefits assures symmetrical treatment of impacts. This symmetrical treatment suggests the program is cost-effective with a BCA ratio of 1.78.

Illustrative Example: Treatment of Host Customer Costs and Benefits

	Asymmetrical	**Symmetrical**	
Costs and Benefits	A. Host Customer Costs **Included**, Benefits **Excluded**	B. Host Customer Benefits and Costs **Both Included**	C. Host Customer Benefits and Costs **Both Excluded**
DER Costs			
Utility System Costs	$7,500		
• Rebate/incentive	$1,875	$1,875	$1,875
• Administrative Costs	$1,500	$1,500	$1,500
Host Customer Costs	$5,625	$5,625	
Total Costs Accounted for:	$9,000	$9,000	$3,375
DER Benefits			
Utility System Benefits	$6,000	$6,000	$6,000
Host Customer Non-Energy Benefits		$4,000	
Total Benefits Accounted for:	$6,000	$10,000	$6,000
Net Benefit	($3,000)	$1,000	$2,625
Benefit-Cost Ratio:	0.67	1.11	1.78

Both Scenarios B and C adhere to the *Ensure Symmetry* principle, and therefore either would be appropriate to apply to a JST, depending upon how the jurisdiction chooses to account for host customer impacts. This example does not include other possible non-utility system impacts, for simplicity, but those impacts would also be included in the JST if consistent with applicable policy goals.

*Even if regulators and others decide to include host customer impacts in its primary test, the host customer benefits from bill savings should not be included in the test because (a) bill savings represent lost revenues, which should not be included in BCA tests (per the *Conduct BCAs Separately from Rate Impact Analyses* principle), and (b) bill savings overlap considerably with utility system avoided costs which are already included in the test, and double-counting should be avoided (per the *Avoid Double-Counting Impacts* principle.)

Applying the principle of symmetry sometimes requires estimating "net" impacts for certain types of benefits. For example, if environmental or economic development benefits are included in the cost-effectiveness framework, it is important to also include environmental and economic development costs as well.

Account for Relevant Impacts, even if Hard to Quantify

Once a jurisdiction has identified which relevant impacts of DERs to include in its primary cost-effectiveness test, these impacts should be accounted for in monetary terms to the extent that it is practical to do so. If an impact is deemed to be immaterial to the test (i.e., to be so small that it is not likely to affect the outcome of test) then it does not need to be included when applying the primary test. This is especially applicable if it would be burdensome or expensive to develop reasonable inputs for the impact.

For example, ancillary services are clearly a utility system impact and therefore should be included in any BCA test. However, for some DERs the impacts on ancillary services might be immaterial and, therefore, do not need to be included when applying the primary test. For other DERs, ancillary services might be material and therefore should be included when applying the test. In both cases, ancillary services are included in the *definition* of the primary test. Yet for one DER, they are not estimated for the *application* of the test because they are deemed immaterial, while in another case they are estimated.

Some approximation may be necessary to establish values of certain relevant impacts that are deemed to be material. Table 3-4 summarizes six different approaches that can be used to account for material impacts of DERs (see Appendix C). While some of these approaches represent approximations and include some uncertainties, 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. Any benefit or cost value used in DER BCAs should be based on a logical, documented, justified method and should not be arbitrary or contrived.

While some DER impacts are difficult to quantify in monetary terms—either due to the nature of the impact or the lack of available information about the impacts—approximating hard-to-quantify impacts is preferable to assuming that the relevant benefits and costs do not exist or have no value.

Table 3-4. Different Approaches to Account for All Relevant Impacts

Approach	Description
Jurisdiction-specific studies	Jurisdiction-specific studies on DER benefits and costs offer what can be the most accurate approach for estimating and monetizing relevant impacts.
Studies from other jurisdictions	If jurisdiction-specific studies are not available, studies from other jurisdictions or regions, as well as national studies, can be used for estimating and monetizing relevant impacts.
Proxies	If monetized impacts are not available, well-informed and well-designed proxies can be used as a simple substitute. For example, the benefits of a DER could be increased by a specified percentage (e.g., x% adder) to account for difficult-to-quantify benefits.
Alternative thresholds	Pre-determined thresholds for determining cost-effectiveness that are different from a 1.0 benefit-cost ratio (BCR) can be used as a simple way to account for relevant impacts that are not otherwise included. For example, resources with a BCR of 0.95 could be deemed cost-effective as an alternative to monetizing difficult-to-quantify benefits.
Accounting for non-monetized impacts	Relevant qualitative information can be used to consider impacts that cannot be monetized.

Avoid Double-Counting Benefits and Costs

The *Avoid Double-Counting Impacts* principle requires not counting impacts more than once and not ignoring impacts because they appear to overlap with others. This can be achieved by clearly defining and valuing each benefit and cost to identify where there might be overlaps or gaps.

Accounting for risk and resilience provides an example of how double-counting can occur. Utilities and host customers might both experience risk and resilience benefits from DERs. For cost-effectiveness tests that account for both utility system and host customer impacts, it is important to ensure that some or all risk and resilience benefits are not counted more than once.

Treat All DERs Consistently

The *Treat DERs as a Utility System Resource* principle states that all DERs types should be compared with other energy resources, and should be evaluated using consistent cost-effectiveness principles, methodologies, and assumptions. This begins with using the same primary cost-effectiveness test for all DERs, whether a jurisdiction is conducting separate single-DER analyses or multi-DER analyses.

In some cases, STEP 1 of the process, *Articulate Applicable Policy Goals,* may be challenging to apply where jurisdictions have different policy goals for different DER types, making it difficult to establish a single primary test for all DER types. For example, a jurisdiction might have a statute or a commission order indicating that the environmental benefits of distributed PV should be accounted for in BCAs, but no such requirement for EE or other DER types. In these cases, there are several options regulators can use to determine which policy goals to account for in the primary test for all DERs:

- Use a narrow interpretation of policy goals, where the primary test accounts for only those policy goals that are applicable to *every* DER type.

If different primary tests are used for different DER types, the BCAs may lead to sub-optimal DER choices, resulting in increased costs to customers and missed opportunities to achieve policy goals.

- Use a broad interpretation of policy goals, where the primary test accounts for every policy goal that is applicable to *any* DER type.
- Do something in between where the *highest priority* policy goals associated with *any* DER type are included regardless of how frequently they apply to different DER types.

> Regulators, with stakeholder input, may need to interpret legislation, regulations, orders, and other policy directives to determine what they imply about the primary cost-effectiveness test.
>
> Appendix B provides template tables that jurisdictions can use to articulate and assess applicable policy goals.

The decision on which approach to take could have significant implications for the primary DER test and the DER assessments. Consistent with the *Transparency* principles, stakeholder input is important for informing the regulator's determination of how best to align policy objectives consistently across the multiple DER analysis.

If a jurisdiction is unable to develop a single primary DER test, secondary tests could be used to promote consistency in the BCA of all DERs. For example, the primary test could be based on a broad interpretation of policy goals, while a secondary test could be based on a narrow interpretation of policy goals. (See Section 3.5.)

Treating DERs consistently in BCAs also requires that benefit and cost assumptions are consistent across DER types. The inputs and per-unit values used for the impacts of different DER types should be the same or based on the same methodologies and assumptions, accounting for differences in magnitude, timing, or location where warranted. For example, the values for avoided energy or avoided generation capacity for any given time or location should be the same for all DER types.

STEP 5 ESTABLISH COMPREHENSIVE, TRANSPARENT DOCUMENTATION

This final step in developing a primary BCA test applies the *Ensure Transparency* principle, whereby cost-effectiveness practices document all relevant inputs, assumptions, methodologies, and BCA results. Such documentation can include, for example:

- An inventory of applicable policy goals used to identify impacts for the primary test;
- A description of the utility system benefit and cost assumptions, including sources of values;
- A description of the non-utility system benefit and cost assumptions, including sources of values;
- BCA modeling parameters such as the study period and discount rates; and
- A summary of the results of the BCA, including all the benefits and costs, the monetary results, the non-monetary results, and the justification of the ultimate resource decision.

Appendix B provides template tables a jurisdiction can use to take inventory of its applicable policies, and to help identify associated benefits and costs. Chapter 13 and Appendix D provide guidance on how to present BCA results in ways that are most informative and most useful in making cost-effectiveness decisions. It also provides guidance on how to present results to support efforts to prioritize across different DER types.

Further, the *Ensure Transparency* principle extends to the *process* of developing a jurisdiction's cost-effectiveness practices. This includes primary and secondary test considerations, where the above information is shared and reviewed with input from interested stakeholders to allow for robust review and input. Such stakeholders include utilities, evaluators, consumer advocates, low-income representatives, state agencies, DER industry representatives, environmental advocates, and others. Stakeholder input is important at the outset of the BCA process for assessing and interpreting applicable policy directives, as they can provide critical viewpoints regarding the value of DERs in the context of the jurisdiction's policy goals.

Stakeholder input can be achieved through a variety of means, as appropriate for a given jurisdiction, such as via:[11]

- Rulemaking processes,
- Generic jurisdiction-wide dockets,
- Utility commission orders on specific DERs, and/or
- Working groups or technical sessions.

The process should address objectives based on current jurisdiction policies and should also be flexible to address new or modified policies that are adopted over time.

Some jurisdictions may wish to incorporate input from government agencies or representatives that do not typically make decisions regarding DER cost-effectiveness but would nonetheless have insights on the jurisdiction's applicable policy goals. For example, a state's public utility commission may wish to incorporate input from that state's department of environmental protection or department of health and human services.

3.4 Jurisdiction-Specific Tests and Traditional Tests

When a jurisdiction develops its own JST using the NSPM BCA Framework, or refines an existing test using the NSPM process, it might result in a test that is different from one of the traditional tests or it might result in a test that is identical to the theoretical definition of a traditional test. Table 3-5 provides a high-level comparison of the use of a JST relative to the traditional tests.

[11] In many jurisdictions, BCA processes involve proceedings with expert testimony, where supporting information, assumptions and practices must be admissible and reliable, and must stand up to discovery, and where applicable, to cross-examination and litigation.

Table 3-5. Jurisdiction-Specific Test Compared with Traditional Tests

Test	Perspective	Key Question Answered	Categories of Benefits and Costs Included
Jurisdiction-Specific Test	Regulators or decision-makers	Will the cost of meeting utility system needs, while achieving applicable policy goals, be reduced?	Includes the utility system impacts, plus those impacts associated with achieving applicable policy goals
Utility Cost Test*	The utility system	Will utility system costs be reduced?	Includes the utility system impacts
Total Resource Cost Test	The utility system plus host customers	Will utility system costs and host customers' costs collectively be reduced?	Includes the utility system impacts, plus host customer impacts
Societal Cost	Society as a whole	Will total costs to society be reduced?	Includes the utility system impacts, plus host customer impacts, plus societal impacts such as environmental and economic development impacts

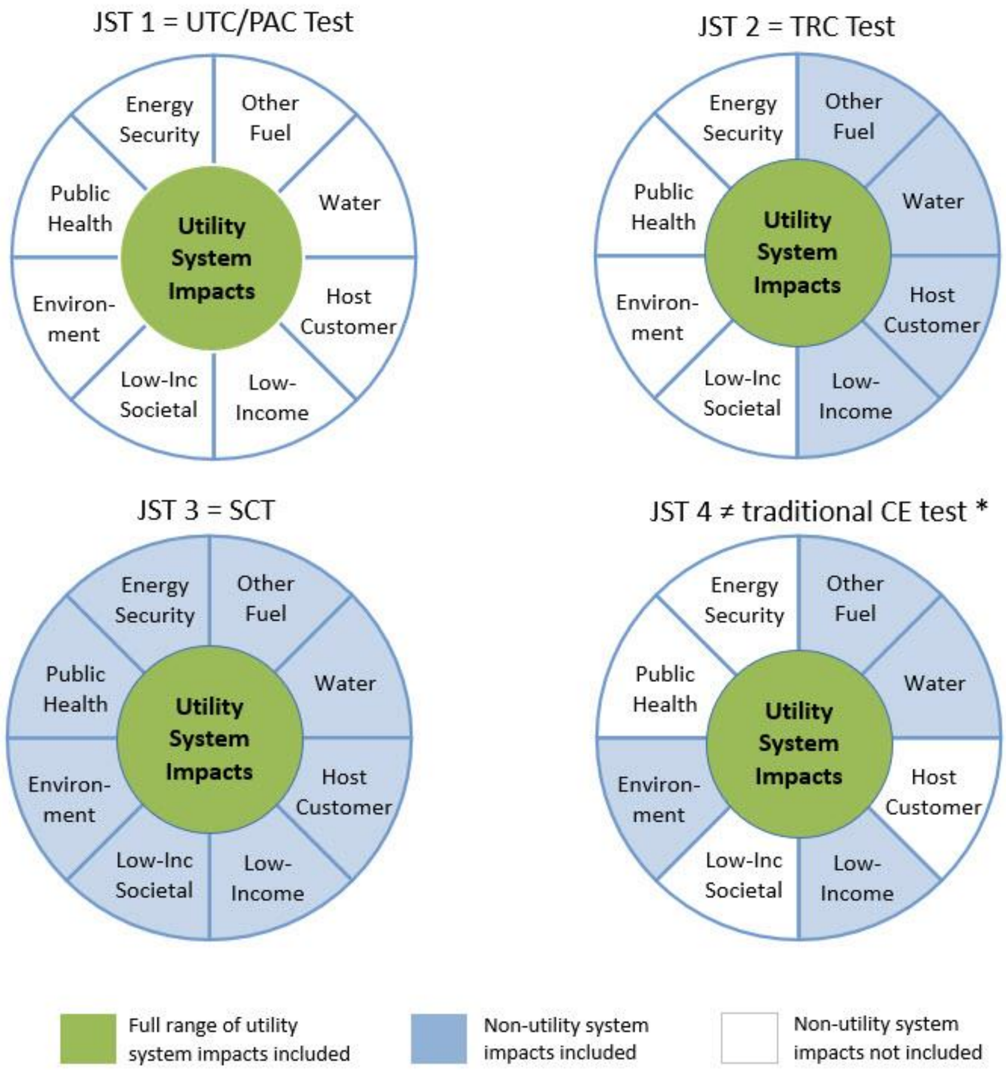
**Also referred to as the Program Administrator Cost (PAC) Test.*

Figure 3-2 presents illustrative primary JSTs, as compared to traditional tests. The figure shows that:

1. In all cases, the full range of utility system impacts are accounted for, consistent with the *Treat DERs as a Utility System Resource* principle.
2. JST 1, 2, and 3 provide examples of where a JST aligns with the UCT, the TRC test, and the SCT, respectively, *assuming* in each case the JST reflects that jurisdiction's specific applicable policy goals.
3. In the JST 4 example, the jurisdiction's specific policies lead to a primary test that is different from any of the traditional tests. This example assumes that the hypothetical jurisdiction has statutes, regulations, orders, or other policy directives that require or suggest that these impacts be accounted for when assessing DER cost-effectiveness.

Importantly, Figure 3-2 illustrates the flexibility provided by the JST.

Figure 3-2. Example Jurisdiction-Specific Test Relative to Traditional Tests



*JST 4 and other example JSTs 5, 6, 7 etc. could include a different set of non-utility system impacts *depending on the applicable policies* of those jurisdictions. JSTs may or may not include host customer (participant) impacts, and may or may not align with traditional tests.

3.5 Developing Secondary BCA Tests

While a jurisdiction's primary test should be used to inform whether a utility should fund or otherwise support DERs, it does not have to be utilized in a vacuum. In some instances, secondary tests can help enhance regulators' and stakeholders' overall understanding of DER impacts by answering other questions regarding utility DER investments.

The key uses for secondary tests include:

- Informing decisions on how to prioritize DERs (including reviewing DERs from perspectives other than the regulatory perspective, such as the host customer perspective);
- Informing decisions regarding marginally cost-effective DERs; and
- Encouraging consistency in BCA analyses across different DER types.

While the primary test, the JST, should be used as the best indication of cost-effectiveness, and thus given the most weight, resource selection may also be supported by one or more secondary tests. For example, secondary tests can indicate the relative priority of different DERs, or how to treat DERs that are marginally cost-effective.

Different tests provide different information about the cost-effectiveness and impacts of DERs. However, secondary tests should be used cautiously to ensure that they do not make the BCA decision-making process burdensome or undermine the purpose of the primary test.

There is a range of options that regulators, utilities, and other stakeholders can consider for secondary tests. Examples include:

- *Utility Cost Test.* The UCT might be useful as a secondary test to provide a benchmark to compare all DER types. This test provides a useful indication of how DERs will affect utility system costs.
- *Societal Cost Test.* The SCT might be useful as a secondary test to indicate how cost-effective DERs would be when accounting for the full range of potential benefits and costs.
- *A "Narrow Secondary test"* based on a narrow interpretation of the jurisdiction's policy goals, where the test accounts for only those policy goals that are applicable to every DER type.
- *A "Broad Secondary test"* based on a broad interpretation to the jurisdiction's policy goals, where the test accounts for every policy goal that is applicable to any DER type. This will help achieve consistency but may give undue weight to some policy goals.
- *A secondary test that includes (or excludes) a particular non-utility system impact* that regulators and stakeholders want to investigate separately from the primary test. This might be useful for conducting a sensitivity analysis of that non-utility system impact.

Decisions on which impacts to include in secondary tests should be driven by the purpose(s) of the secondary analyses. The main purposes of secondary tests are discussed below.

3.5.1 Inform Decisions on How to Prioritize DERs

While the primary test indicates which DERs merit utility acquisition on behalf of customers, some jurisdictions may choose not to invest in all cost-effective DERs due to funding limits, equity concerns, or other constraints. In these cases, regulators, utilities, and others may need to make choices among cost-effective DERs to decide which ones to implement.

Regulators and stakeholders may choose to prioritize programs based on the results of the primary test. For example, DERs could be ranked according to their net benefits or benefit-cost ratios, and the lower-cost ones could be chosen over the higher-cost ones.

Alternatively, regulators with input from stakeholders may choose to use a secondary test to help prioritize DERs. For example, the UCT could be useful for prioritizing DERs because it focuses on the direct benefits and costs to the customers that are funding the utility-sponsored DER. Or regulators may decide not to invest in DERs that, for the host customer, have a very short payback period (e.g., less than one year as indicated by the PCT). (See Chapter 13.)

3.5.2 Inform Decisions Regarding Marginally Cost-Effective Resources

In cases where a DER is marginally cost-effective, secondary tests can be used to decide whether the utility should fund or otherwise support the DER. Secondary tests provide regulators and other stakeholders with additional information to assess whether certain DER investments will provide net benefits.

For example, consider a jurisdiction where stakeholders are divided on whether to account for the benefit of GHG reductions in the primary test, and the regulators decide not to account for them. In this case, a secondary test that does account for the benefits of GHG reductions might be useful. If a proposed DER has a benefit-cost ratio under the primary test of just below 1.0, and a benefit-cost ratio under the secondary test of nearly 2.0, then regulators with input from stakeholders might choose to invest in this DER because of the GHG benefits. Alternatively, if the benefit-cost ratio under the primary test is 0.85, and 1.05 under the secondary test, regulators and stakeholders might choose to not invest in this DER.[12]

If secondary tests are used to inform decisions regarding marginally cost-effective DERs, regulators and other stakeholders may want to establish protocols for how they should be used. Figure 3-3 presents an example of protocols that could be used for this purpose.

[12] In addition to showing how including a particular impact in the BCA test will affect the BCA results, sensitivity analyses can also be used to show how different estimates for an impact (e.g., low, medium, high estimates) will affect the BCA results.

Figure 3-3. Example Use of Secondary Tests for Marginally Cost-Effective DERs

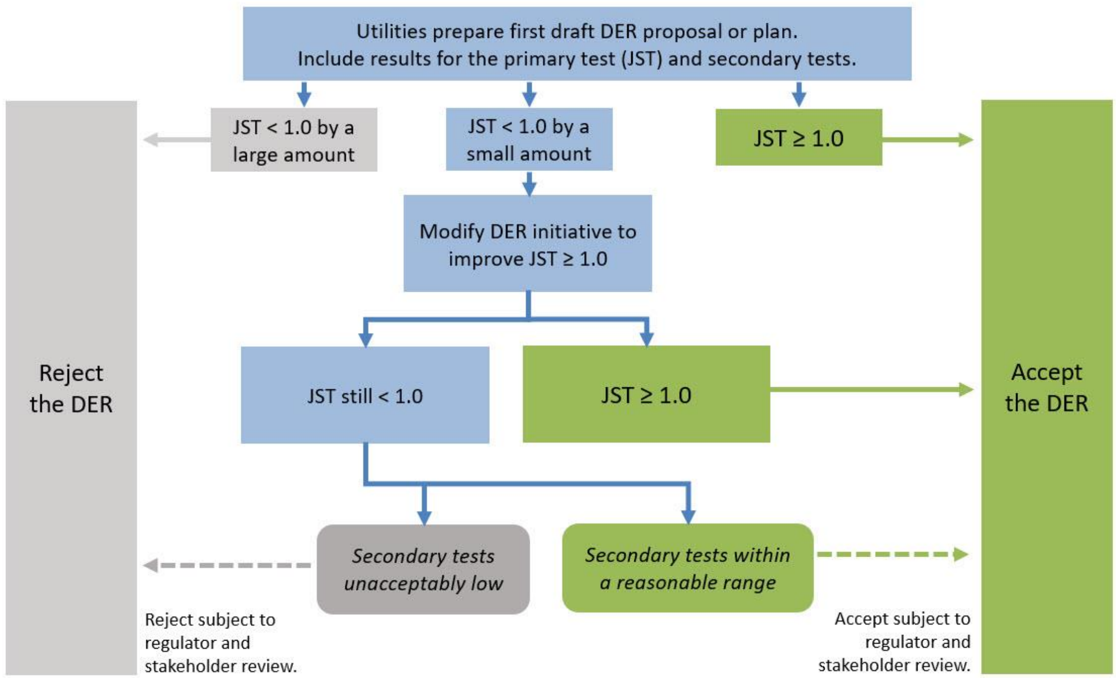


Table 3-6 presents some examples of how secondary tests could be used to make decisions regarding marginally cost-effective DERs. In this example, the primary test includes all utility system impacts, low-income impacts, and other fuels. The secondary test includes those impacts plus benefits of reducing GHG emissions. The conclusions are summarized as follows:

- *Case 1.* The primary test indicates that the DER is cost-effective. There is no need to apply a secondary test. The DER is accepted for utility funding or support.
- *Case 2.* The DER is accepted for utility funding or support even though the primary test indicates that the DER(s) is not cost-effective.
- *Case 3.* The primary test indicates that the DER is marginally cost-effective, but the secondary test indicates that the DER is not cost-effective even after accounting for GHG emissions. The DER is not accepted for utility funding or support.
- *Case 4.* The primary test indicates that the DER is not even marginally cost-effective, and so is not accepted for utility funding or support despite the secondary test indicating cost-effectiveness.

Table 3-6. Examples of Secondary tests Used to Consider Marginal DERs

	Case 1	Case 2	Case 3	Case 4
Primary test (JST)	2.1	0.96	0.96	0.8
Secondary test	Not needed	1.8	0.98	1.8
Investment Decision	accept	accept	reject	reject

Using secondary tests in this way may diminish the prominence of the primary JST test, as shown in Case 2. On the other hand, the secondary test alone may not determine investment decisions, as shown in Case 4. This implies that secondary tests should be used carefully and with full documentation of the process and bases for making investment decisions.

3.5.3 Promote Consistency Across Multiple DER Types

As described in Chapter 2, the *Treat DERs as a Utility System Resource* principle requires that all DER types be evaluated using consistent cost-effectiveness principles, methodologies, and assumptions.

If a jurisdiction analyzes multiple DER types together, then the best way to ensure consistency across DER types is to use the same primary cost-effectiveness test for all DER types. See Part IV for guidance and case studies on developing multiple-DER tests. If a jurisdiction is having difficulty developing a single primary test to evaluate all DERs, (for instance, due to attributes of each DER or how different DERs are addressed in the jurisdiction's policies) then secondary tests can again be helpful to promote consistency across DERs. Several options are available for secondary tests. (See Section 3.5.)

A Narrow Test

If regulators and others choose to apply a single primary test that accounts for the *broadest* set of policy goals, then a secondary test that accounts for a *narrower* set of policy goals associated with one DER type could be designed to indicate how the BCA results would be different for that DER type under that test.

If that DER type is found to be cost-effective under both tests, then no more investigation is needed. If that DER is found to be cost-effective under the primary test, but not under the narrower secondary test, additional investigation might be warranted. The DER might be deemed cost-effective if the secondary test results indicate that it is marginally cost-effective (for example, with a benefit-cost ratio slightly below 1.0). The DER might be deemed not cost-effective if the secondary test results indicate that it is not even marginally cost-effective (for example, with a benefit-cost ratio well below 1.0).

A Broad Test

If regulators choose to apply a single primary test that accounts for the *narrowest* set of policy goals, then a secondary test that accounts for a *broader* set of policy goals associated with one DER type could be designed. Again, if that DER type is found to be cost-effective under both tests, then no additional investigation is warranted. If not, then regulators and others might want to consider the results of the secondary test.

3.5.4 Other Uses for Secondary Tests

There are other situations where a cost-effectiveness test that is not the primary test is useful for purposes other than cost-effectiveness analyses. For example, the UCT can be helpful in mitigating equity concerns through program design. The financial incentives offered to DER host customers could be capped at a level equal to the utility system avoided costs. This would prevent customers that do not host DERs from paying more than the benefits they receive from the DER resource.

PART II:
DER BENEFITS AND COSTS

Overview

This part of the manual describes the types of benefits and costs that can be created by DERs.

Chapter 4 presents a catalog of the range of benefits and costs that might be applicable to any DER type, including a brief description of each type of impact. The benefits and costs are organized by:

- electric utility system,
- gas utilities and other fuel systems,
- host customer, and
- societal impacts.

Chapter 5 discusses a variety of considerations that span several of the benefits and costs described in Chapter 4. These include:

- temporal impacts,
- locational impacts,
- interactive impacts,
- behind-the-meter versus front-of-the-meter impacts,
- air emission impacts,
- transfer payments and off-setting impacts,
- variable renewable generation impacts,
- wholesale market revenues,
- free-riders and spillover impacts, and
- discount rates.

Together, Chapters 4 and 5 feed into Part III (Chapters 6–10) which describe whether and how the range of benefits and costs apply to different DER technologies.

4. DER BENEFITS AND COSTS

This chapter presents a catalog of the range of benefits and costs that might be applicable to any DER type, including a brief description of each type of benefit or cost. Chapter 5 describes some additional issues that span multiple types of benefits and costs. Chapters 6 through 10 describe how these benefits and costs apply to different DER types.

4.1 Summary of Key Points

- DERs can have a wide range of impacts that can affect the electric utility system, the gas utility and other fuels systems, host customers, and society.
- While some impacts are definitively a benefit or cost for several DER types, other impacts can be either a benefit or a cost depending on factors, such as where the DER is located and when and how it operates.
- For DERs funded or otherwise supported by *electric* utilities, all BCAs should include the electric utility system impacts, and may include gas utility and other fuel system impacts, host customer impacts, and/or societal impacts (depending on the jurisdiction's applicable policy goals).
- For DERs funded or otherwise supported by *gas utilities or other fuel* vendors, all BCAs should include the gas utility or other fuel system impacts respectively, and may include the electric utility impacts, host customer impacts, and/or societal impacts (depending on the jurisdiction's applicable policy goals).
- Information presented in this chapter is based on the assumption that each DER type is implemented and operated in isolation from other DER types. When a BCA encompasses multiple DER types, the impacts might be different than those presented in this chapter. For example, some costs might become benefits and vice versa, and the net impact may be different than the sum of the individual DER impacts. Part IV of this manual provides further discussion on the implications of multiple DER cost-effectiveness analyses.

4.2 Utility System Impacts

4.2.1 Summary

Table 4-1 presents a list of the potential electric utility system impacts of DERs. This table includes impacts on the electric utility system that occur when either electric or gas utilities support DERs that have impacts on electricity consumption.

In some situations, these impacts might be in the form of costs, while in other situations they may be in the form of benefits (i.e., avoided costs). For example, EE programs will typically reduce electricity generation, creating a benefit, while electrification resources will typically increase electricity generation, creating a cost. As another example, DG that is fueled by renewable resources will typically reduce environmental compliance costs, but DG that is fueled by fossil fuels will typically increase environmental compliance costs.

Chapters 6–10 provide details on the impacts presented below for each DER type.

Table 4-1. Potential DER Benefits and Costs: Electric Utility System

Type	Utility System Impact	Description
Generation	Energy Generation	The production or procurement of energy (kWh) from generation resources on behalf of customers
	Capacity	The generation capacity (kW) required to meet the forecasted system peak load
	Environmental Compliance	Actions to comply with environmental regulations
	RPS/CES Compliance	Actions to comply with renewable portfolio standards or clean energy standards
	Market Price Effects	The decrease (or increase) in wholesale market prices as a result of reduced (or increased) customer consumption
	Ancillary Services	Services required to maintain electric grid stability and power quality
Transmission	Transmission Capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably
	Transmission System Losses	Electricity or gas lost through the transmission system
Distribution	Distribution Capacity	Maintaining the availability of the distribution system to transport electricity or gas safely and reliably
	Distribution System Losses	Electricity lost through the distribution system
	Distribution O&M	Operating and maintaining the distribution system
	Distribution Voltage	Maintaining voltage levels within an acceptable range to ensure that both real and reactive power production are matched with demand
General	Financial Incentives	Utility financial support provided to DER host customers or other market actors to encourage DER implementation
	Program Administration	Utility outreach to trade allies, technical training, marketing, and administration and management of DERs
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of DER programs
	Credit and Collection	Bad debt, disconnections, reconnections
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks
	Reliability	Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions

4.2.2 Generation Impacts

Energy Generation

Definition: Expenses from the production or procurement of energy (i.e., kWh) from generation resources on behalf of customers. These expenses include the fuel cost and variable operations and maintenance (O&M) costs. Energy generation costs can vary by season and time of day.

Discussion: In general, DERs will create energy generation benefits when they reduce the amount of electricity utilities need to produce or procure in order to meet load and will create 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 EV charging) results in a benefit and curtailing grid energy consumption results in a cost.

The direction and scale of this impact fluctuates over time. In terms of system conditions, the negative pricing example shows how the real-time balance in supply and demand will dictate the direction of the impact while the level of system load will drive the scale of the impact (i.e., generally higher during peak periods).

Generation Capacity

Definition: The amount of generation (i.e., kW) required to meet the forecasted peak load,[13] 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.

Discussion: The effect of a DER on generation capacity is limited to instances when a DER's operation is coincident with the utility system peak load. If a DER's operation results in a net increase in load (such as with electrification) during the system peak, the utility will incur additional generation capacity costs. Alternatively, if a DER's operation results in a net decrease in load (e.g., EE savings; curtailment through demand response; PV generation; injections from storage) during the system peak, the utility will derive a benefit in the form of lower generation capacity needs.

Environmental Compliance

Definition: There are several environmental regulations that impact the utility system. These can include federal regulations like the Clean Air Act, regional mandates such as the Regional Greenhouse Gas Initiative (RGGI), or state and local mandates. These regulations typically require a reduction in emissions from energy generation or place limits on allowable levels of emissions from new or existing resources.

Discussion: While some environmental regulations place a fixed limit on the amount of emissions for new or existing resources, determining a DER's net effect on this impact typically requires an analysis of the marginal emissions rate of the resource being displaced by the DER (see Section 5.6). For example, if a DG resource's output occurs when the marginal supply resource for the utility system is an emitting resource, it will result in a benefit. Alternatively, if a DPV resource's generation occurs when a non-emitting resource (e.g., solar, wind, nuclear) is the marginal resource, then the DPV resource would provide neither a benefit nor a cost.

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[13] Jurisdictions may have alternative approaches for defining peak (e.g., single peak hour, a certain percentage of top load hours, etc.).

In some cases, it is important to consider and avoid double-counting impacts when, for example:

- Criteria pollutants are regulated through a cap-and-trade program—the environmental compliance impacts might already be included in the energy generation cost. It is important to ensure that any such embedded environmental compliance impacts are not double-counted by including them in this category.
- Considering the relationship between environmental compliance impacts and societal environmental impacts—environmental compliance impacts are the direct impacts in dollar terms that will be experienced by the utility and passed on to all customers through revenue requirements. Therefore, these impacts are utility system impacts that should be included in all BCA tests.[14] Societal environmental impacts, on the other hand, are the impacts on the environment that occur after environmental compliance regulations have been met. Therefore, for those BCA tests that include societal environmental impacts, it is important to distinguish them from environmental compliance impacts in order to prevent double-counting.
- Distinguishing between environmental compliance impacts and societal environmental impacts for the purpose of rate, bill, and participation analyses—environmental compliance impacts are utility system impacts that will affect rates 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, and should not be included in rate, bill, and participation analyses.

In estimating environmental compliance impacts, a BCA should account for all regulations that have already been promulgated and are in effect. It should also account for all regulations that are expected to be in effect over the study period (Regulatory Assistance Project 2012). If there is uncertainty about future environmental regulations, then this can be addressed through sensitivity analyses or expected value calculations. (For example, if the likelihood of future promulgation is 70 percent, the environmental compliance cost can be multiplied by 70 percent.)

Renewable Portfolio Standard Compliance

Definition: A renewable portfolio standard (RPS) is a regulatory mandate to increase production of energy from renewable sources such as wind, solar, biomass, and other alternatives to fossil fuel-based electric generation. This impact may also include similar regulatory mechanisms like clean energy standards (CES) that more generally focus on zero-emissions resources (e.g., nuclear, hydro), or clean peak standards (CPS) that encourage clean energy resources that can mitigate the utility system peak.

Discussion: In jurisdictions that have adopted an RPS or similar mechanism expressed as a percentage of electric sales, DERs can reduce RPS compliance costs either by reducing the RPS target by virtue of lowering overall electricity demand or increasing the level of qualified renewable generation.[15] Alternatively, if a DER has the effect of increasing electricity demand (e.g., electrification), it will require additional renewable purchases and therefore increase RPS compliance costs.

Wholesale Market Price Effects

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

[14] Except for the PCT.

[15] The utility must be able to claim the renewable energy attribute by retaining ownership of renewable energy credits (REC) from renewable DG to realize the benefit of reduced RPS compliance costs. In some cases, the host customer may choose to retain the RECs and thus renewable DG would not reduce the utility's RPS compliance costs.

reduce (or increase) the demand for electricity, they reduce (or increase) the wholesale market prices, which creates benefits (or costs) for all customers participating in the wholesale market at that time. A similar effect can be seen in wholesale natural gas markets from the reduction in natural gas demand from DERs (AESC Study Group 2018).

Wholesale market price effects are different from energy generation, generation capacity, and ancillary services impacts. The former is the impact on *prices* from a change in demand, which will affect all buyers from the wholesale markets. The latter is the impact on the *costs* associated with consuming a different amount of a commodity.

Discussion: DERs can impact wholesale market prices either in the form of demand (e.g., DPV treated as a utility load modifier) or supply (e.g., demand response participation directly in the wholesale market). This market price effect might be relatively small, but the impacts are felt by all customers buying from the market at the time of the effect, and therefore the total impact can be significant. This impact typically lasts for only a short period before the market adjusts to the new supply/demand balance (AESC Study Group 2018).

Market price effects from DERs located in a given utility service territory may extend beyond the borders of that service territory because of the regional nature of most wholesale markets, which tend to encompass multiple utility service territories. Thus, regulators need to decide whether to include the market price effects for (a) only the utility service territory in question, (b) the entire jurisdiction under the regulator's purview, or (c) for the entire wholesale market region. This decision should be based on the regulatory perspective and applicable policy goals for each jurisdiction.

Wholesale market price effects are sometimes referred to as a "transfer payment" between competitive suppliers and wholesale market buyers because the benefit to one is directly offset by the cost to another. However, this is a misleading conclusion. While it is true that the impact on wholesale market buyers' costs is offset by the impact on suppliers' profits, both impacts should be included in a BCA because both the buyer's costs and the supplier's profits are a part of the benefits and costs of the electricity resource. This issue is addressed further in Section 5.7 and Appendix F.

Ancillary Services

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.

Description: As with other impacts, a DER's net effect on ancillary services depends on how the DER operates 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.

4.2.3 Transmission Impacts

Transmission Capacity

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.

Discussion: As with generation capacity, a DER's impact on transmission capacity depends on how it operates 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 NWS. 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 NWS; 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.

Transmission System Losses

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.

Discussion: To the extent DERs offset utility-scale energy generation (e.g., DG meeting host customer load) they will help avoid electricity transmission and as a result reduce the cost associated with transmission line losses. However, to the extent utility-scale energy generation is needed to meet any incremental load from DERs (e.g., electrification or storage and EV charging) the costs associated with transmission line losses will increase. The magnitude of the impact will depend on the amount of transmission-level load at the time of the DER's operation.

As with electric transmission line losses, gas transmission systems also experience "pipe losses," though they tend to be much smaller in magnitude (in percentage terms) compared to electric losses.

4.2.4 Distribution Impacts

Distribution Capacity

Definition: Distribution capacity refers to substation and distribution line infrastructure necessary to meet customer electric demand, and as such the net impact will depend on the cost associated with the specific type of distribution infrastructure being affected. If customer 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 how they operate during the distribution system peaks.

Discussion: 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, DER’s 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 create voltage issues) it would have the effect of creating a cost to invest in the necessary distribution infrastructure to avoid these issues.

Distribution System Losses

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.

Discussion: 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.

Like electric distribution line losses, gas distribution systems also experience “pipe losses,” though they tend to be much smaller in magnitude (in percentage terms) compared to electric losses.

Distribution O&M

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, and 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.

Discussion: 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 in nature can lead to increased distribution costs due to the need to manage energy flows to maintain voltage and frequency within acceptable limits.

Distribution Voltage

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 (RMI 2015).

Discussion: DERs can either exacerbate or help address emerging voltage issues on the distribution system. Quantifying this impact requires analysis of when a DER will operate relative to real-time system conditions. Additionally, care must be taken to ensure any impact associated with distribution voltage is not double-counted for another impact (e.g., ancillary services; distribution capacity).

4.2.5 General Impacts

Financial Incentives

Definition: 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.

Discussion: 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.

Program Administration Costs

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

Discussion: 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 and/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.

Utility Performance Incentives

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.

Discussion: 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.

Credit and Collection Costs

Definition: Costs associated with customers who are deficient on energy bill payments, including notices and support provided to customers in arrears, shutting off service and turning it back on, carrying costs associated with arrears, and writing off bad debt.

Discussion: To the extent a DER has 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.

Risk

Definition: The utility system can be exposed to several categories of risk, including operational (e.g., equipment breakdown or damage) technology, cybersecurity, financial, legal, regulatory, and reputational risks.

Discussion: DERs can reduce utility system risk in several ways. Key among them are that DERs:

- create a more diverse portfolio of resources that can meet customers' energy needs (all other things being equal, diversity typically reduces risk);
- reduce uncertainty in forecasts of future loads and related capital investment needs;
- reduce exposure to potential future fuel price volatility associated with other resource types (particularly natural gas, oil, and/or coal-fired generation) (Ceres 2012); and
- can transfer some financial risk away from the utility and non-participating customers to the host customers, in cases where host customers are putting up the capital to install the DER.

Also, as a resource that can be implemented in many relatively small increments, DERs provide more optionality than large central generation facilities. For example, once a utility decides to build a 200 MW natural gas-fired power plant to meet customer demand, it will be locked into that resource for the three or four years it takes to construct the power plant. If DERs are installed instead of that plant, then the utility will have those three of four years to determine whether it needs those 200 MW. If load growth turns out to be lower than expected over this time, then the utility might be able to reduce costs to customers by installing less than 200 MW of DER capacity.

DERs can also increase utility system risk in several ways. For example, some DERs may:

- have risks associated with host customers' willingness and ability to respond to DR signals;
- pose technical performance risks, particularly for new and emerging technologies;
- create a cybersecurity risk by virtue of creating a larger number of entry points to the electricity network;
- increase electricity or gas demand, which might increase risks to those utilities; or
- create risk in cases where DERs are controlled by customers or independent technology providers, because the utility does not directly control the operation of those resources.

It is important to avoid double-counting of risk, reliability, and resilience impacts.

Reliability

Definition: The U.S. Department of Energy defines reliability as the ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components (DOE 2017c, page 4-1). Reliability has typically been tracked by utilities using metrics related to the frequency, duration, and extent of power outages experienced by customers (e.g., system average interruption duration index, system average interruption frequency index, and customer average interruption duration index).

Discussion: By lowering loads or increasing generation on the grid, DERs can reduce the probability and/or duration of customer service interruptions. 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. It is important to avoid double-counting of risk, reliability, and resilience impacts.

Resilience

Definition: NARUC defines resilience as "Robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event" (NARUC 2019).

Discussion: DERs can create resilience impacts in several ways. Some DERs, such as storage and DG, can provide power to the host customer, the local grid, or a micro-grid during an outage. Some DERs can increase the resilience of the overall energy system by providing black start (starting without power from the grid) or ramping capabilities. Some DERs can increase resilience by reducing the amount of load that needs to be served to recover from an outage. It is important to avoid double-counting of risk, reliability, and resilience impacts.

4.2.6 Cross-Cutting Utility System Impacts

Some impacts of DERs are not specific to any one utility system impact as they apply to more than one impact. As such they are not included in Table 4-1 because they are not mutually exclusive, i.e., they are cross-cutting impacts. These cross-cutting impacts, described below, will typically affect the magnitude of some of the other impacts presented in Table 4-1. They can be accounted for by either modifying the magnitude of those impacts or accounting for them separately. Either way, it is important to ensure that there is no double-counting of these cross-cutting impacts with other utility system impacts.

Enabling other DERs

Some DERs can make it easier or more cost-effective to adopt other types of DERs, thereby creating a benefit. (See Section 5.4.) Examples of how this can occur include:

- Distributed storage technologies can be combined with distributed PV or wind to improve the economics of each by storing excess generation during periods of low electricity costs and discharging from the storage device during periods of high electricity costs (ACEEE 2020). This arrangement may also have the effect of increasing hosting capacity.
- Multiple DERs can be combined in an NWS to help defer or avoid a distribution investment that could not be deferred or avoided by a subset of those DERs.
- Commercial and industrial lighting controls that are installed as part of an EE initiative can also be used as a DR resource.

Grid Flexibility

Operational flexibility of the electric grid is becoming increasingly valuable for grid operators to meet the needs of an increasingly dynamic grid. Some DERs can provide savings, generation, or ancillary services quickly, thereby enhancing flexibility of grid operations. Some DERs allow for shifting and shaping loads, thereby allowing for meeting peak demands with greater flexibility (typically referred to as demand flexibility). Some DERs can operate using two-way communications with grid operators, thereby enhancing their ability to respond quickly and flexibly to price and other signals. (DOE 2019a; SEE Action 2020b; RAP 2019b.)

Grid flexibility impacts will typically affect the magnitude of the DER impacts presented in Table 4-1. For example, grid flexibility might reduce generation capacity costs, ancillary services costs, transmission costs, and distribution costs. Grid flexibility might also increase risk, reliability, and resilience benefits.

The economic value of grid flexibility has not been studied as much as the values of some of the other utility system impacts of DERs. Further, the economic value of grid flexibility will depend upon many factors specific to the DER being studied, including the timing and use case of the DER operation; the location of the DER on the grid; the type of grid services provided by the DER; the expected service life of the DER; and the value of other resources that would provide comparable services (SEE Action 2020c).

Impacts Associated with Time-of-Use Rates

Definition: TOU rates provide customers with an incentive to shift load from high-cost peak periods to low-cost off-peak periods. TOU rates are designed to be revenue neutral for the utility (i.e., they provide the utility with the same amount of revenue as they would receive in the absence of the TOU rates).[16] TOU rates sometimes require utility system costs in the form of administration, metering, and billing costs. TOU rates provide utility system benefits by reducing demand during high-cost hours.

Discussion: TOU rates can result in a shifting of cost recovery from customers with low-cost consumption patterns to those with higher-cost consumption patterns. Cost-shifting between customers is a different matter from cost-effectiveness and should not be accounted for in BCAs. It is nonetheless of great importance to regulators and other stakeholders. Those regulators concerned about cost-shifting from TOU rates should conduct rate, bill, and participation analyses to assess the implications of those rates. (See Chapter 2 and Appendix A.)

Market or Technology Transformation

Some utility DER initiatives can transform markets and technologies, resulting in lower costs and new opportunities to expand deployment. A common example is ratepayer-funded utility EE programs. These programs have been shown to lower the cost of new technologies and increase customer awareness and acceptance to the point where little to no utility incentives are needed for certain technologies. Some efficient end-uses, such as efficient lighting technologies, have been so widely adopted and commercialized as a result of EE programs that they no longer need to be supported by utility EE programs.

4.3 Gas Utility and Other Fuel System Impacts

4.3.1 Summary

There are two situations where DERs will have impacts on natural gas and other fuels. First, when natural gas utilities implement or otherwise support gas DERs there will be impacts on the natural gas utility system and perhaps other fuels. Second, when electric utilities implement or otherwise support DERs there are sometimes impacts on natural gas and other fuels. This section describes the impacts created by either of these two situations.

Table 4-2 presents a list of the potential impacts on gas utilities from gas utility DERs. For example, an EE program offered by a natural gas utility can result in gas utility fuel, variable O&M, and capacity benefits. Such programs can also result in costs associated with financial incentives, program administration, and utility performance incentives.

[16] TOU rates are often designed to be revenue neutral to the utility based on historical consumption patterns. When customers change consumption patterns based on the TOU price signals, the revenue recovered from those customers will be different from historical revenue collections. In these cases, the TOU rate in itself is not revenue neutral.

Table 4-2 also includes the potential impacts on gas utilities and other fuels from electric utility DERs. Examples of gas and other fuel impacts from electric utility DERs include the reduced consumption of natural gas space heating that results from electric utility EE programs that provide air sealing to reduce air conditioner loads, the increased consumption of natural gas or other fuels from DR programs that rely upon back-up generators, the increased consumption in natural gas or other fuels resulting from an electric utility CHP program, and the reduced consumption in gasoline as a result of electric utility EV programs.

In some situations, these impacts might be in the form of costs, while in other situations they may be in the form of benefits. For example, a natural gas DR program might create natural gas capacity benefits, while an electric DR program that relies upon natural gas for back-up generation might create natural gas capacity costs.

Chapters 6–10 provide details on the impacts presented below for each DER type.

Table 4-2. Potential Benefits and Costs of DERs: Gas Utility or Other Fuel Impacts

Type	Gas Utility or Other Fuel Impact	Description
Energy	Fuel and Variable O&M	The fuel and O&M impacts associated with gas or other fuels
	Capacity	The gas capacity required to meet forecasted peak load
	Environmental Compliance	Actions required to comply with environmental regulations
	Market Price Effects	The decrease (or increase) in wholesale prices as a result of reduced (or increased) customer consumption
General	Financial Incentives	Utility financial support provided to DER host customers or other market actors to encourage DER implementation
	Program Administration Costs	Utility outreach to trade allies, technical training, marketing, and administration and management of DERs
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of DER programs
	Credit and Collection Costs	Bad debt, disconnections, reconnections
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks
	Reliability	Maintaining the gas or other fuel system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions

4.3.2 Energy Impacts

Fuel and Variable O&M

Definition: Utilities and other energy suppliers incur expenses from the procurement of fuel (e.g., natural gas, oil, propane) on behalf of customers, including any related variable O&M costs. This can include the costs related to the transport of natural gas from delivery points located on interstate and intrastate pipelines to customers.

Discussion: Some DERs will create fuel and variable O&M benefits when they reduce the amount of natural gas, fuel oil, propane, and wood that utilities and energy suppliers need to produce or procure to meet customer demand. Among the most common examples are EE measures such as insulation, air sealing, high efficiency boilers and furnaces, and electrification (e.g., heat pumps). Alternatively, some DERs like fossil fuel-powered combined heat and power systems or fuel cells may increase consumption of these other fuels. Furthermore, electric efficiency resources can reduce the "waste heat" from inefficient lighting, refrigeration, or air flow components, thereby increasing the need for other fuels used for building space heating.

Capacity

Definition: Natural gas utilities contract for firm pipeline transport and storage capacity to meet customer demand. This ensures that pipeline capacity is available when needed to distribute natural gas to customers with firm service contracts.

Discussion: The impact for DERs depends on how their operation affects other fuel consumption during peak hours. For example, gas EE or DR programs—potentially as part of a non-pipes solution (NPS)—can lower demand for gas supply during peak times and create benefits. Alternatively, if DERs increase demand on other fuel capacity during peak times (e.g., CHP; fuel cells), it will create an added cost for the utility.

Environmental Compliance

Definition: There are costs associated with environmental regulations for gas utility and other fuel systems (e.g., caps on methane emissions). This is comparable to the environmental compliance costs for electricity resources described earlier. (See Section 4.2.2.)

Discussion: As with other impacts, the net effect of a DER on environmental compliance depends on how it affects consumption of natural gas and other fuels: if it lowers consumption, it will produce a benefit, and vice versa. (See Section 4.2.2.)

Wholesale Market Price Effects

Definition: Wholesale markets for natural gas, oil, propane, and other fuels are a function of the magnitude of demand and the marginal costs of supply-side resources. 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 at that time (AESC Study Group 2018). This is similar to the wholesale market price effects for wholesale electricity markets. (See Section 4.2.2.)

Discussion: (See Section 4.2.2.)

4.3.3 General Impacts

Financial Incentives

Definition: 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.

Discussion: Financial incentives may come in various forms, including rebates for DER technologies, 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.

Program Administration Costs

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

Discussion: 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 and/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.

Utility Performance Incentives

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.

Discussion: 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. Some jurisdictions might include penalties for not meeting performance targets.

Credit and Collection Costs

Definition: Costs associated with customers who are deficient on energy bill payments, including notices and support provided to customers in arrears, shutting off service and turning it back on, carrying costs associated with arrears, and writing off bad debt.

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

Risk

Definition: The utility system can be exposed to several categories of risk, including operational (e.g., equipment breakdown or damage) technology, cybersecurity, financial, legal, regulatory, and reputational risks. This impact is comparable to the risk impacts for electric utility systems described earlier. (See Section 4.2.5.)

Discussion: Some DERs can reduce risks associated with natural gas and other fuels, while others might increase risks. (See Section 4.2.5.)

Reliability

Definition: The U.S. Department of Energy defines reliability as the ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components (DOE 2017c, page 4-1).

Discussion: DERs that reduce natural gas consumption during peak periods (e.g., EE, DR, electrification) can improve reliability through eliminating or reducing demand spikes and pipeline constraints. This can help to reduce the probability and/or likely duration of natural gas and other fuel delivery interruptions. There could be some overlap between this benefit and the benefits of reduced risk and avoided capacity costs. Therefore, any assessment of the value of increased reliability would need to ensure that there is no double-counting of overlap with such other benefits.

Resilience

Definition: The National Renewable Energy Laboratory defines resilience as "The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions through adaptable and holistic planning and technical solutions" (NREL 2019, page 2).

Discussion: Natural gas infrastructure is susceptible to the impacts of climate change, including sea level rise and flooding that can cause loss of service and in extreme cases damage to pipelines. However, there is limited research available on the impacts of DERs to natural gas system resilience.

4.4 Host Customer Impacts

4.4.1 Summary

Table 4-3 presents a list of the potential host customer impacts of DERs. The term "host customer" is used to refer to a customer that installs a DER in their home or business. The host customer might be a participant in a utility-sponsored 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.

In some situations, these impacts can be in the form of benefits, while in other situations they can be in the form of costs. In most cases, the portion of 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 host customer NEIs, the impacts can be in the form of either benefits or costs. Chapters 6–10 provide details on the impacts presented below for each DER type.

Table 4-3. Potential Benefits and Costs of DERs: Host Customer

Type	Host Customer Impact	Description
Host Customer	Host portion of DER costs	Costs incurred to install and operate DERs
	Host transaction costs	Other costs incurred to install and operate 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
	Host Customer NEIs	Benefits and costs of DERs that are separate from energy-related impacts
	Low-income NEIs	Non-energy benefits and costs that affect low-income DER host customers

4.4.2 Host Customer Energy Impacts

Host Customer Portion of DER Costs

Definition: Host customer costs include those costs incurred to install and operate a DER.

Discussion: Utility financial incentives (e.g., rebates) are often provided to defray some of the incremental costs of DERs. In those cases, the host customer DER cost includes only the portion of the DER cost not covered by the financial incentive.

Host Customer Transaction Costs

Definition: Transaction costs associated with the acquisition and installation of DERs.

Discussion: These costs can include time spent collecting information, obtaining quotes from multiple vendors, filing paperwork, and applications for rebates and other financing mechanisms. This impact will always manifest itself as a cost for the host customer.

Interconnection Fees

Definition: Costs associated with the utility and/or ISO/RTO interconnection process paid for by the host customer.

Discussion: Utilities typically require some DERs (e.g., DG and energy storage) to pay costs to interconnect to the utility grid. This usually requires host customers (or their vendors) to provide an application with relevant data on equipment, sizing, energy production, and location to ensure they meet necessary standards. Utilities charge an interconnection fee to cover the cost of the application and inspection process. In some cases, more detailed engineering analyses are required with the host customer being responsible for the additional costs.

Similarly, if a DER owner seeks to participate in the wholesale market and is subject to an ISO/RTO interconnection process, they may incur interconnection costs from the ISO/RTO. In some cases, host customers might incur both the ISO/RTO and utility interconnection costs. It is important to ensure that this cost is not double-counted with the host customer portion of DER costs (many installers will submit and pay for the interconnection fee on behalf of customers as part of the total cost of the system).

Risk

Definition: Host customers may face changes in risk levels related to price volatility, power quality, outages, and operational risk associated with the failure of installed DER equipment and user error. This type of risk may depend on the type of DER.

Discussion: DERs may increase or reduce risks to host customers. Reduced risks result from lowering a customer's exposure to high prices by reducing consumption during peak periods and reducing a customer's exposure to fossil fuel price volatility. Increased risks might result from technology performance, particularly in situations where DERs participating in wholesale electricity markets are exposed to non-performance penalties. It is important to avoid double-counting of utility and host customer risk impacts.

Reliability

Definition: Reliability refers to the ability of host customers to access energy supply when needed.

Discussion: DERs that can provide customers with access to power during a system outage (e.g., DG plus storage) can increase reliability. There could be overlap between this benefit and the benefit of resilience, and therefore any assessment of the value of increased reliability would need to ensure that there is no double-counting with other impacts. It is important to avoid double-counting of utility and host customer reliability impacts, as well as for risk, reliability, and resilience impacts.

Resilience

Definition: Resilience refers to the ability of host customers to avoid, mitigate, or quickly respond to power outages.

Discussion: DER systems with ride-through or islanding capacity[17] (e.g., storage) can be used to provide energy in the event of a power outage and create a resiliency benefit in the form of continued supply of electricity for medical and health uses, continued business operations, safety and security, and other functions. In addition, some DER measures can offer short-term resilience benefits (e.g., in case of efficiency, high levels of insulation allow customers to remain comfortable without heating fuel for longer periods). It is important to avoid double-counting of utility, host customer, and societal resilience impacts, as well as for risk, reliability, and resilience impacts.

Tax Incentives

Definition: Federal, state, and local tax incentives are sometimes available to host customers to defray the costs of some DERs. One example is the federal solar investment tax credit to encourage investments in distributed solar energy.

Discussion: Whether to include host customer tax incentives in a BCA depends upon the particular BCA test used. If the host customer impacts are outside of the test, then host customer tax incentives are not relevant. If both host customer impacts and taxpayer impacts are within the scope of the test, then host customer tax incentives should not be included because they offset each other. If host customer impacts are within the scope of the test but taxpayer impacts are not, then host customer tax incentives should be included in the test because there is no offsetting impact. (See Section 5.7 and Appendix F.)

Table 4-4 indicates how these factors play out in different tests. The JST can either align with one of any of the traditional tests below, and have consistent treatment of tax incentives, or it can be a unique test that requires different treatment. In the example presented below the JST does not include taxpayers within the scope of the test.

[17] The term “ride-through” capacity refers to the ability of DERs to be able to operate during a power outage. The term “islanding” capacity refers to the ability to isolate a set of customers to operate independently from the rest of the grid, e.g., with a micro-grid.

Table 4-4. Treatment of Host Customer Tax Incentives in Different Tests

Test Used	Host Customer Impacts Within Scope?	Taxpayer Impacts Within Scope?	Include Tax Incentives?
Utility Cost Test	—	—	—
Total Resource Cost Test	✓	—	✓
Jurisdiction Specific Test: Example	✓	—	✓
Societal Cost Test	✓	✓	—

4.4.3 Host Customer Non-Energy Impacts

Definition: DERs can create a variety of non-energy impacts (NEIs) for host customers that are separate from the energy saved or produced by DERs. Table 4-5 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. The presence, direction, and magnitude of these impacts will depend upon many factors, including the type of DER (e.g., EE, DR, DG, storage, electrification, EVs), the specific DER technology (e.g., EE lighting versus EE building conditioning), the type of host customer (e.g., low-income, residential, commercial, industrial), and more.

Table 4-5. Potential Host Customer Non-Energy Impacts

Host Customer NEI	Summary Description
Transaction costs	Costs incurred to adopt DERs, beyond those related to the technology or service itself (e.g., application fees, time spent researching, paperwork)
Asset value	Changes in the value of a home or business as a result of the DER (e.g., increased building value, improved equipment value, extended equipment life)
Productivity	Changes in a customer’s productivity (e.g., changes in labor costs, operational flexibility, O&M costs, reduced waste streams, reduced spoilage)
Economic well-being	Economic impacts beyond bill savings (e.g., reduced complaints about bills, reduced terminations and reconnections, reduced foreclosures—especially for low-income customers)
Comfort	Changes in comfort level (e.g., thermal, noise, and lighting impacts)
Health & safety	Changes in customer health or safety (e.g., fewer sick days from work or school, reduced medical costs, improved indoor air quality, reduced deaths)
Empowerment & control	The satisfaction of being able to control one’s energy consumption and energy bill
Satisfaction & pride	The satisfaction of helping to reduce environmental impacts (e.g., one of the reasons why residential customers install rooftop PV)

Discussion: Some NEIs can be difficult to quantify and monetize. By their nature, DER non-energy costs and costs are less well known and harder to research than utility system impacts and host customer direct benefits or costs. In addition, the host customer NEIs might vary considerably depending upon the type of customer, the customer’s facility, the type of DER, and the operation of the DER. Further, there has been little empirical research on host customer NEIs for some DERs, such as DPV, storage, and EVs.

Nonetheless, the fact that host customer NEIs can be difficult to quantify and monetize does not mean that they should be ignored in cost-effectiveness analyses. First, the *Account for Relevant, Material Impacts* principle states that impacts that are relevant (i.e., within the scope of a BCA test) and material (i.e., are expected to have a material impact on the results) should be accounted for in the BCA, regardless of whether they are hard to quantify. (See Chapter 2, Section 3.4, and Appendix C.)

Second, the *Ensure Symmetry* principle requires that cost-effectiveness practices be symmetrical, where both benefits and costs are included for each relevant type of impact, even if difficult to quantify. This means that if a BCA test includes host customer costs, then it must also include host customer benefits, including non-energy benefits. Similarly, if a jurisdiction decides that host customer NEIs should not be included in a BCA test, then other host customer impacts should not be included either.

Low-Income Host Customer Non-Energy Impacts

Definition: Low-income customers experience similar NEIs as non-low-income customers, but in some cases, they are distinctly different.

Discussion: Low-income NEIs can come in two forms. First, low-income NEIs include the same *types* of NEIs as realized by non-low-income residential participants (e.g., economic well-being, comfort, health, safety). The *magnitude* of some of these benefits are often greater for low-income customers than for non-low-income customers. This is because the condition of the low-income housing stock is often worse and/or because the economic stress under which low-income customers live can result in greater sacrifice of amenity (e.g., comfort) absent efficiency investments.

Second, some host customer NEIs are unique, or largely unique, to this subset of customers. Examples include reduced home foreclosures and reduced need to move residence as a result of unpaid bills.

Host Customer Bill Savings

Definition: DERs typically result in bill savings for the host customer. In some cases, e.g., electrification, the DER might increase the host customer electricity bill but decrease the costs of other fuels such as natural gas or gasoline, resulting in a net decrease in energy costs for the host customer.

Discussion: Host customer bill savings should not be included in cost-effectiveness tests used to determine which DERs warrant utility support on behalf of all utility customers. Host customer bill savings overlap significantly with 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.[18] Further, host customer bill savings will result in rate impacts, which should be analyzed separately from cost-effectiveness analyses. (See Chapter 2 and Appendix A).

Host customer bill savings should, however, be included in the PCT because that test is designed to represent the actual impacts on host customers, including bill savings. In the PCT, the bill savings are the primary benefits of DERs, but the utility system benefits are not included at all. Similarly, host customer bill savings should be accounted for in the RIM Test because that test is designed to identify how DERs will impact rates.

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[18] 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, marginal generation, transmission, and distribution costs.

4.5 Societal Impacts

4.5.1 Summary

Table 4-6 presents a list of the potential societal impacts of different DER types.

In some situations, these impacts might be in the form of costs, while in other situations they may be in the form of benefits (i.e., avoided costs). For example, EE programs will typically reduce electricity generation, creating a benefit, while electrification resources will typically increase electricity generation, creating a cost. As another example, DG that is fueled by renewable resources will typically reduce environmental compliance costs, but DG that is fueled by fossil-fuels will typically increase environmental compliance costs.

Chapters 6–10 provide details on the impacts presented below for each DER type.

Table 4-6 presents a list of the potential societal impacts for different DER types. These impacts are relevant for parties other than the electric utility, gas utility, other fuel provider, or host customer.

Table 4-6. Potential Benefits and Costs of DERs: Societal

Type	Societal Impact	Description
Societal	Resilience	Resilience impacts beyond those experienced by utilities or host customers
	GHG Emissions	GHG emissions created by fossil-fueled energy resources
	Other Environmental	Other air emissions, solid waste, land, water, and other environmental impacts
	Economic and Jobs	Incremental economic development and job impacts
	Public Health	Health impacts, medical costs, and productivity affected by health
	Low Income: Society	Poverty alleviation, environmental justice, and reduced home foreclosures
	Energy Security	Energy imports and energy independence

4.5.2 Types of Societal Impacts

Resilience

Definition: Same as for electric and gas utility or other fuel systems.

Discussion: Society can realize DER resilience benefits that are above and beyond the benefits that accrue to utilities, fuel suppliers, and host customers. Some DERs (e.g., DG combined with storage) allow for critical facilities such as hospitals, fire stations, police stations, water treatment facilities, and more to continue providing services during a planned or unplanned power outage. The services that these critical facilities provide to society go beyond the benefits enjoyed by the host customers themselves. It is important to avoid double-counting between societal, utility system, and host customer resilience benefits.

Greenhouse Gas Emissions

Definition: 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. Societal GHG emissions represent the emissions that occur *after* compliance with environmental 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.

Discussion: The magnitude of DER GHG impacts will depend upon the marginal GHG emissions rate of the resources that are affected by the DER, which in turn will depend upon when the DER operates. The marginal GHG emission rates from a utility system can vary considerably across hours, days, and months, and can also vary considerably across utility systems and utility control areas. (See Sections 5.2 and 5.6.)

For DERs that impact multiple fuels (e.g., electrification, EVs) it is important to identify the environmental impact of all fuels affected by the resource. Electrification and EVs will typically increase the GHG emissions from the electricity industry but will reduce the GHG emissions from other fuel sources. Both effects are necessary to derive the net impact on GHG emissions.

It is important to distinguish between environmental compliance impacts and societal GHG impacts for the following reasons:

- Environmental compliance impacts are utility system impacts that should be included in all BCA tests.[19] Societal GHG impacts, on the other hand, are the impacts on the environment that occur after environmental compliance regulations have been met and should be included only in those BCA tests that include societal GHG impacts.
- In the context of rate, bill, and participation analyses, environmental compliance impacts are utility system impacts that will affect rates and therefore should be included in rate, bill, and participation analyses. Societal GHG impacts, on the other hand, are not utility system impacts, will not affect rates, and therefore are not appropriate to include in rate, bill, and participation analyses.

Other Environmental

Definition: Energy resources can have a variety of environmental impacts beyond GHG emissions. These include other air emissions, liquid and solid waste emissions, land use, water use, and more. Societal environmental impacts represent the impacts that occur *after* compliance with environmental regulations and requirements. These societal impacts are referred to as "externalities" because the impacts are external to the monetary prices of the goods that create them.

Discussion: As with GHG emissions, other environmental impacts from DERs typically depend upon the energy resources that are affected by the DER, which in turn will depend upon when the DER operates. Therefore, other environmental impact estimates should be based on as much temporal granularity as possible. (See Sections 5.2 and 5.6.)

Similarly, it is important to identify the other environmental impacts of all fuels that are affected by the DER, such as the impacts of gasoline consumption that are affected by EVs.

As with GHG emissions, it is important to distinguish between environmental compliance impacts and societal environmental impacts, both for determining which impacts to include in BCA test and for conducting rate, bill, and participation impacts.

[19] Except for the PCT.

Economic Development and Jobs

Definition: The value of any incremental economic development and jobs provided by DERs.

Discussion: Economic development impacts from energy resource investments include three categories of impacts:

- *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.

DERs contribute to these three categories of impacts, primarily through two different phases. The first phase is during the installation of the DER, which might last a year or two. The second phase is during the operation of the DER, which lasts many years over the full operating life of the DER. In the second phase, most of the job and economic activity impacts are created when the host customers spend the money that they have gained from reduced energy bills (ACEEE 2019a).

All investments in energy resources will have economic development impacts. While DERs will typically increase economic development, they will displace other energy resources that also would have increased economic development. Estimates of DER economic development and job impacts should account for both the impacts of DERs and the energy resources that they displace, in order to adhere to the *Ensure Symmetry* principle.

Economic development can be expressed in several ways, including employment (in job-years), gross domestic product (in $), personal income (in $), or state tax revenues (in $). Since these different expressions of economic development are interrelated and overlapping, a jurisdiction cannot simply take the sum of them individually to derive the net impact. Consequently, the choice of which way to express economic development can have a significant effect on the monetary value of this impact.

Monetary estimates of economic development impacts should not be added to the monetary cost-effectiveness analysis results, because they represent a different type of economic impact (Synapse 2019, Appendix B). The economic development benefits represent economic activity in the state, which is different from the customer and societal impacts included in an energy efficiency program BCA.

The number of job-years is a potentially useful metric to present alongside BCA results, because job growth is easily understood and relatively easy to isolate from the other indicators.

Public Health

Definition: Some energy resources create health impacts for populations impacted by fuel extraction, combustion, and transportation. These health impacts have implications for (a) the health and well-being of the affected populations, (b) the societal investment required in medical facility infrastructure, and (c) the economic productivity of the affected populations (RAP 2013a).

Discussion: There is potential for considerable overlap between other environmental impacts and public health impacts. It is important to define and address both types of impacts carefully to avoid double-counting or under-counting of impacts.

Low-Income: Society

Definition: Low-income community or societal impacts that go beyond those realized by host customers. Some examples include poverty alleviation, local environmental justice benefits, improving low-income community strength and resiliency, and reduced home foreclosures.

Discussion: There is potential for considerable overlap between low-income host customer impacts and low-income societal impacts. It is important to address both types of impacts carefully to avoid double-counting or under-counting of impacts. For example, any societal impacts from reduced foreclosures must be incremental to the host customer impacts related to foreclosures.

Energy Security

Definition: DER investments that reduce imports of various forms of energy help advance the goals of energy independence and security.

Discussion: There is potential for overlap between energy security and utility system reliability and risk. It is important to address both types of impacts carefully to avoid double-counting or under-counting of impacts.

5. Cross-Cutting Benefit and Cost Considerations

This chapter discusses a variety of benefit and cost considerations that span several of the impacts listed in Chapter 4 and across different types of DERs discussed in Chapters 6 through 10.

5.1 Summary of Key Points

- *Temporal and Locational Impacts of DERs*: Several of the benefits and costs of some DERs can vary significantly depending on when the DER operates and where it is located. DER benefits and costs should be estimated using temporal and locational detail sufficient to adequately represent the DER operating patterns and consequent benefits and costs.
- *Interactive effects between DER types*: Some DER types can have interactive effects on other DERs in terms of affecting avoided costs, affecting the magnitude of kWh and kW impacts, and enabling the adoption of other DER types. BCAs should account for these interactive effects for those instances where the effects are likely to have a material effect.
- *Behind versus in front of the meter DERs*: Some DERs are located in front of the meter and are primarily operated to reduce utility system costs, while others are located behind the meter and are primarily operated to reduce customer costs. While the impact categories for these types of DERs are similar, there may be important differences in operation between utility needs and host customer needs that should be identified and accounted for.
- *Air emission impacts*: GHG and other air emission impacts will depend upon when the DER operates and which energy resources are utilized differently at that time. Estimates of GHG and other air emission impacts should account for the temporal and marginal DER impacts in as much detail as necessary to reflect these effects.
- *Transfer payments and offsetting impacts*: There are some situations in DER BCAs where a DER benefit experienced by one party is exactly offset by a corresponding DER cost experienced by another party, and therefore should be excluded from the BCA. For some BCA tests, financial incentives and tax incentives might be offsetting effects and therefore should be excluded from the BCA.
- *Renewable generation impacts*: DERs can affect renewable generation by providing grid flexibility and ancillary services to help with increasing amounts of intermittent generation from these resources. DERs can also reduce (or increase) the need to curtail renewable resources during times when renewable generation exceeds customer load. These impacts on renewable generation should be accounted for when they are expected to have a material effect on the BCA results.
- *Wholesale market revenues*: Some DERs are eligible to participate in wholesale electricity markets, which provide revenues to host customers or DER aggregators. These revenues should not be included in most cost-effectiveness tests because this would result in double-counting of the energy, generation capacity, and ancillary services benefits to the utility system. The one exception is the PCT because this test does not account for utility system benefits and the

wholesale market revenues are experienced by the host customers in addition to the bill savings.

- *Discount rates*: The choice of discount rate to use for a BCA might have a large effect on the result of the analysis. This choice should be guided by the jurisdiction's applicable policy goals and the regulatory perspective.

5.2 Temporal Impacts

DER impacts can vary depending on the specific timing of the DER's operation, because of temporal variation in system conditions (LBNL 2019). For example, generation costs and air emissions vary considerably over time depending upon which power plant is on the margin. As another example, DERs can provide greater benefits to the system if they relieve transmission and/or distribution capacity constraints during times of peak loading, but alternatively could result in added transmission and/or distribution capacity costs if their operation increases load during peak periods. Table 5-1 indicates which DER impacts are most likely to have temporal variation.

Table 5-1. DER Impacts Typically Affected by Temporal Variation

Utility System Impacts	Gas and Other Fuel Impacts	Host Customer Impacts	Societal Impacts
Energy generation Generation capacity Environmental compliance Market price effects Ancillary services Transmission capacity Distribution capacity Distribution voltage Risk Reliability Resilience	Fuel and variable O&M Capacity Environmental compliance Risk Reliability Resilience	Risk Reliability Resilience	GHG emissions Other environmental Public health Resilience

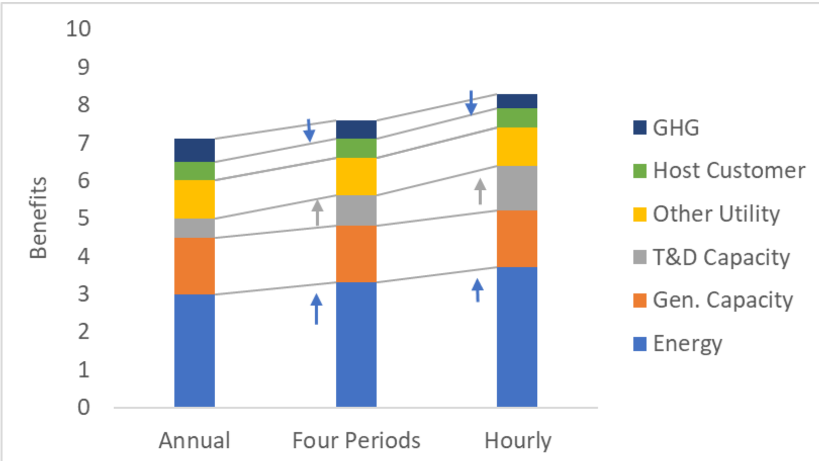
Figure 5-1 provides a hypothetical example of the effect that temporal variations can have on an EE resource's benefits. This example presents six categories of benefits for an EE resource, and how they might vary depending upon whether the benefits are based on annual averages, averages for four periods (winter on- and off-peak and summer on- and off-peak), or hourly data. This example assumes the EE resource provides a larger portion of savings during peak periods than off-peak periods.

In this example:

- The energy generation benefits are higher in the four periods case and higher still in the hourly case because these cases allow for a better breakout of peak versus off-peak hours.
- The T&D capacity benefits are also higher in the four periods case and higher still in the hourly case because these cases allow for a better breakout of peak versus off-peak hours.
- The GHG benefits are slightly lower in the four periods case and lower still in the hourly case. This is because for this hypothetical electricity system the higher emission resources are on the margin during peak periods and this effect is captured better with more granular data.
- The generation capacity, other utility, and host customer benefits do not change as a result of more granular temporal information.

In practice, the magnitude and direction of the impacts presented here could vary from this illustrative example, depending upon the DER, its operating pattern, its location, and other factors. For example, for an EE resource that provides a larger portion of savings during off-peak periods relative to peak periods, the energy and T&D benefits might be lower as a result of more granular data.

Figure 5-1. Example of Temporal Impacts on Energy Efficiency Benefits



DER benefits and costs should be estimated using enough temporal detail to adequately represent the DER operating patterns and consequent benefits and costs. For some DERs, such as EE and DR, it may be sufficient to use four periods per year to adequately capture temporal impacts; whereas for other DERs, such as storage or vehicle-to-grid (V2G) it might be necessary to use hourly or sub-hourly periods.

Although the goal of measuring impacts with greater temporal granularity is to derive a more accurate estimate of actual impacts, it may also entail greater levels of uncertainty. For example, while there are several industry references available that provide prototypical DER performance on an hourly basis, there is greater uncertainty in deriving these prototypical performance curves on a sub-hourly basis.

5.3 Locational Impacts

DER impacts can vary depending on where they are located on the distribution system. Like the temporal impacts discussed in Section 5.2, locational impacts vary depending on dynamic system conditions (e.g., the cost to generate, transmit, and distribute electricity). For example, transmission and/or distribution capacity constraints may make it more valuable for DERs to be sited in locations where their operation can help alleviate the constraint. Alternatively, a DER located in an area of the distribution system with more limited hosting capacity may require distribution system upgrades to preserve distribution safety and reliability. Table 5-2 indicates which DER impacts are most likely to have locational variation.

Table 5-2. DER Impacts Typically Affected by Locational Variation

Utility System Impacts	Gas and Other Fuel Impacts	Host Customer Impacts	Societal Impacts
Energy generation Generation capacity Environmental compliance Transmission capacity Distribution capacity Distribution O&M Distribution voltage Interconnection costs Risk Reliability Resilience	Fuel and variable O&M Capacity Environmental compliance Risk Reliability Resilience	Risk Reliability Resilience	Resilience Other environmental Public health

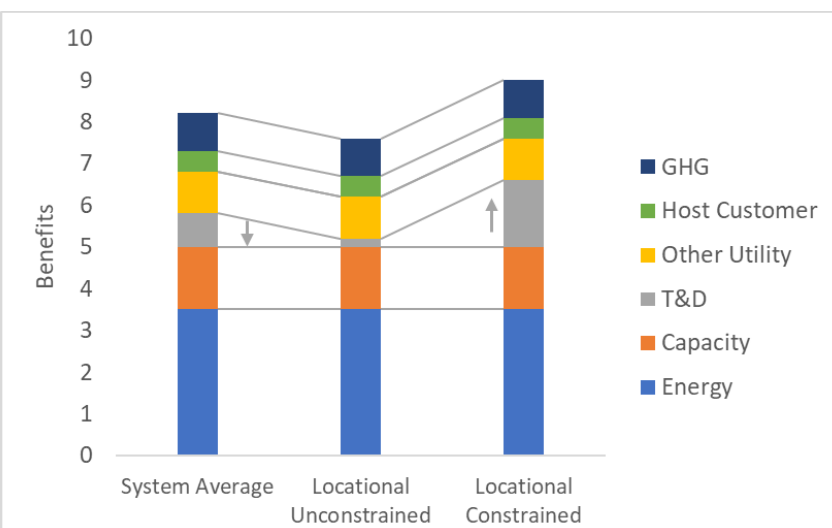
Figure 5-2 provides a hypothetical example of the effect that locational variations can have on a DER's benefits. This example presents six categories of benefits for a DR resource, and how they might vary depending upon whether the benefits are based on the system average, a location where distribution capacity is not constrained, and a location where distribution capacity is constrained.

In this example, the distribution benefit is the only impact that changes across the three cases:

- For the system average, there is a moderate distribution benefit based on the average benefits across the utility system.
- For the unconstrained location, the distribution benefit is zero, leaving only the transmission benefit.
- For the constrained location, the distribution benefit is higher than the system average and the unconstrained location.

In practice, the magnitude and direction of the impacts presented here could vary from this illustrative example, depending upon the DER, its operating pattern, its location, and other factors.

Figure 5-2. Example of Locational Impacts on Demand Response Benefits



DER benefits and costs should be estimated using enough detail to adequately represent the DER locational impacts and consequent benefits and costs. For some DERs where distribution benefits are a relatively small portion of the total benefits, such as EE, it may be sufficient to use system average impacts. For other DERs where more targeted distribution benefits are a significant portion of the benefits (such as DR, storage, and NWSs) it is more important to capture the locational details.

Some impacts might vary by location for some utilities but not others. For example, if energy generation is settled on an ISO/RTO zonal basis and the utility's service territory only spans a single zone, then this impact would not vary depending on where the DER is interconnected. However, if the utility's service territory spans several zones, then the energy generation impacts might vary across those zones.

Although the goal of measuring impacts with greater locational granularity is to derive a more accurate estimate of actual impacts, it may also entail greater levels of uncertainty. For example, while a utility may be able to readily determine impacts at the system level, there is more complexity involved with determining these impacts on a more granular locational level (e.g., having to forecast load growth, DER adoption, and DER operating profiles on a feeder level). BCAs must also consider that locational needs—and hence likely impacts—may change over time due to dynamic system conditions.

ESTIMATING LOCATION IMPACTS – EXAMPLES

California and New York initial efforts to estimate locational impacts can serve as a useful reference for other jurisdictions seeking to develop more robust frameworks for estimating locational DER impacts.

CALIFORNIA

Section 769 of the California Public Utilities Code requires the investor-owned utilities (IOUs) to prepare Distribution Resource Plans (DRPs) that identify optimal locations for the deployment of DERs. The IOUs apply a Locational Net Benefit Analysis (LNBA) methodology, which takes the statewide averaged avoided costs for T&D and unbundles these values into specific sub-categories, such as distribution voltage and power quality, distribution reliability and resiliency, transmission, flexible resource adequacy procurement, and renewables integration. The LNBA Working Group released a Long-Term Refinements Report to the Commission providing recommendations on further refinements and improvements to the LNBA methodology (SDGE, SCE, and PGE 2018). The report addressed many topics and identified six priority topics: (1) locational avoided energy value; (2) locational avoided capacity value; (3) locational avoided line losses value; (4) incorporation of reactive power priority (VAR profiles); (5) automatic input of DER profiles; and (6) locational avoided transmission value.

NEW YORK

As part of the Reforming the Energy Vision initiative, the New York State Public Service Commission established the Value of Distributed Energy Resources (VDER) proceeding and developed a new DER tariff called the Value Stack. The Value Stack was designed initially to replace retail rate net energy metering for some types of DERs, such as community DG and other BTM projects for which customers were already subject to demand metering but the tariff then became more broadly applicable to all DERs. The Value Stack was designed to capture values across five distinct areas: (1) wholesale energy; (2) wholesale capacity; (3) environmental value (i.e. carbon emissions); (4) distribution system-wide value; and (5) targeted locational distribution value (NY PSC 2019).

Like California's LNBA efforts, the last two Value Stack components seek to reflect a more accurate approximation of the distribution value DERs can provide. To derive each of these two value components, the utilities were required to "deaverage" their system-wide marginal cost of service studies into two separate values measuring the impact on avoided distribution costs. The distribution system-wide value, referred to as the Distribution Reduction Value, provides compensation for the average value in avoiding distribution costs at the system level. Alternatively, the more targeted locational value, referred to as the Locational System Relief Value, is only available for DERs located in utility-identified load pockets where these resources are more likely to avoid forecasted distribution upgrades. For both the Distribution Reduction Value and Locational System Relief Value, DERs will only be compensated for their performance during certain hours that are determined to represent the highest system-wide or locational need.

5.4 Interactive Impacts

While Chapter 4 provides an overview of each individual impact, this section focuses on how multiple DERs might influence their impacts collectively. These interactive effects may manifest themselves in three areas: (1) marginal system costs, (2) the magnitude of kW or kWh impacts of other DERs, and (3) enablement of other DER types.

BCA practitioners do not necessarily need to identify all of the impacts of each DER that is used in combination with other DERs. All that matters is the total impacts of all the DERs combined. Nonetheless, it is important to consider the concepts described below in order to understand how the DERs can affect each other in order to determine the total impacts to be input to the BCA.

5.4.1 Impacts on Marginal System Costs

Interactive Effects of Marginal System Costs

Marginal system costs refer to the costs associated with serving the next kW of load. These costs vary over time as a result of changes to the system (e.g., a dynamic supply-demand balance; quality of system infrastructure; changing resource mix; etc.). Marginal system costs are important in DER BCAs because they determine many of the key DER benefits, such as energy and capacity benefits.

When multiple DERs and multiple DER types are installed on a system they might affect the marginal system costs, and thereby affect the avoided costs, of each other. While this effect on marginal system costs may be small and immaterial for each DER or type of DER, the net effect may become increasingly significant as DER deployment increases.

One prominent example of this effect is the duck curve resulting from high deployment of solar resources. As solar resources provide generation during the hours of the day with sunlight, the result will be a lower net load during those hours that might otherwise have been considered the peak hours (and as such, result in lower system marginal costs and lower avoided costs). With enough solar deployment, this effect could be large enough to shift the peak period from the afternoon to the early evening when the solar generation dissipates. As a result of this phenomenon, the impact other resources (e.g., efficient air conditioning) have on marginal system costs during the afternoon hours will be lower than it would have otherwise been at that time.

This type of interactive effect is not limited to just the duck curve. Another example is when a DR program's size and effectiveness is significant enough to materially change either the timing or magnitude of peak generation, transmission, or distribution demands. If this is the case, it will fundamentally affect the on-peak avoided costs of other DERs. Similarly, greater adoption of EE resources will put downward pressure on the marginal cost of energy, which will reduce avoided energy costs for other DER types.

In some instances, TOU rates can be used to help DERs respond to changes in marginal system costs. For example, TOU rate structures could be modified over time to ensure that the peak periods for pricing purposes remain consistent with the peak periods that shift as a result of changes to marginal system costs from DERs.

Accounting for Interactive Effects of Marginal System Costs in DER BCAs

DER cost-effectiveness analyses should account for these interactive effects on marginal system costs where they are likely to have a significant impact on the results of the analysis. These interactive effects will be increasingly significant in jurisdictions with growing DER deployment.

Effectively capturing these interactive effects requires incorporation of DER load impacts into system planning (i.e., IRP, IDP, or IGP) to consider both DERs and supply-side resources as potential solutions to meet system needs. (See Chapter 14.)

For those jurisdictions and utilities that do not use IDP practices, there are several ways to consider or account for impacts on the avoided costs of other DERs.

The first step is to decide whether this effect should be accounted for in the cost-effectiveness analysis. In many cases with relatively low deployment of DERs, the impacts of some DERs on the avoided costs of other DERs might be small. This is the assumption that has been used in many EE and DER cost-effectiveness analyses in the past.

For jurisdictions that decide to account for this effect, there are several approaches to account for how some DERs can affect the avoided cost of other DERs:

- One option is to *estimate which DER types are likely to be the most cost-effective*. For example, if EE and DR resources are likely to be the most cost-effective DER types, then these could be assumed to be implemented first. These resources could be assumed to be in place when the avoided costs for other DERs are estimated. As another example, all the low-cost EE, DR, DG, electrification, and storage technologies could be installed first, then the mid-cost DERs, and then the high-cost DERs.
- Another option is to *modify the avoided costs over time* based upon the assumed implementation of DERs. In other words, the estimate of avoided costs in the second year of the study period could assume a certain amount of DERs are installed in the first year of the study period, etc.
- A further option is to *iterate using different assumptions for avoided costs* under different scenarios. For example, the first set of scenarios could assess the cost-effectiveness of DERs without modifications to the avoided costs. The next set of scenarios could use modified avoided costs that assume that all the cost-effective DERs identified in the first set are in place. This process could continue several times until an equilibrium is reached or there is confidence that the impacts on avoided costs have been sufficiently addressed.

Each of these options has limitations that make them much less accurate than using IDP to dynamically estimate the impacts of DER on marginal system costs. Nonetheless, for those jurisdictions and utilities that do not use IDP, they might be better than ignoring the interactive effects that DERs have on marginal system costs.

5.4.2 Effects on the Magnitude of kWh or kW Impacts of Other DERs

There are many ways that one DER might affect the magnitude of kWh or kW impacts of other DERs. For example:

- When EE resources reduce a customer's peak demand, they will likely reduce that customer's ability to reduce peak demand through DR or storage resources.
- When DG and storage resources are installed by the same customer, the combined benefits of both resources operating together are likely to exceed the benefits of each DER operating without the other. The storage resource will allow the customer to sell DG output back to the grid at times when prices are highest.
- A building with DR resources (e.g., thermostats; hot water heaters) might affect the dispatch parameters of a storage resource within the same building. (See Chapter 11.)
- A utility that sources an NWS may seek to use a portfolio of DERs whose combined interactive effects are best suited to meet the system need. (See Chapter 12.)

Figure 5-3 presents an illustrative example of how interactive effects might influence the benefits of DPV and storage resources. The bar on the left indicates the potential benefits of DPV and storage when each is the only resource installed on a site. The bar on the right indicates the potential benefits of DPV and storage when they are both installed on the same site behind the same meter. This example assumes that the costs of each DER type remain unchanged when they are installed together, for simplicity.

In this example, the energy, generation capacity, and T&D benefits are greater in the case with DPV and storage combined. This is because the storage can be charged and discharged at times that reflect the off-peak and peak times on the system. In practice, the magnitude and direction of the impacts presented here could vary from this illustrative example, depending upon the DERs, their operating patterns, their location, and other factors.

Figure 5-3. Example of Interactive Effects on DPV and Storage

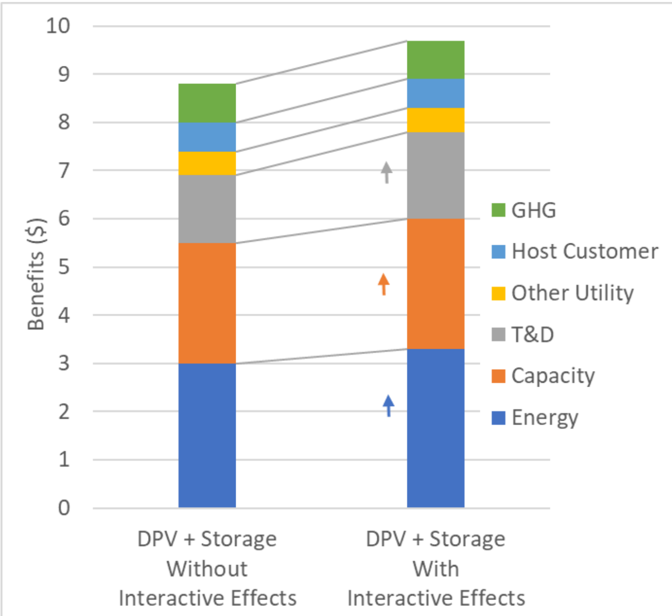
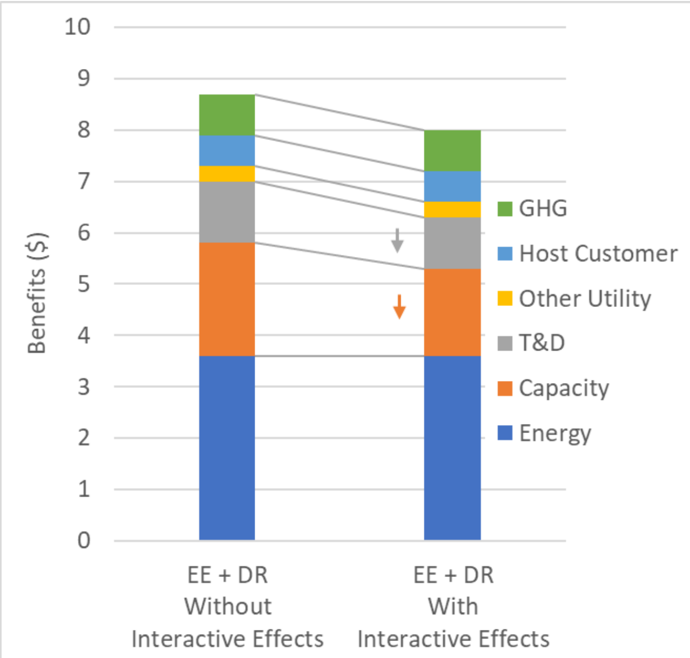


Figure 5-4 presents a different example of how interactive effects might influence the benefits of DERs. The bar on the left indicates the potential benefits of EE and DER when each is the only resource installed on a site. The bar on the right indicates the potential benefits of EE and DR when they are both installed on the same site behind the same meter. This example assumes that the costs of each DER type remain unchanged when they are installed together, for simplicity.

In this example, the generation capacity and T&D benefits are lower in the case with EE and DR combined. This is because the EE resource assumed in this example will reduce the host customer demand during the generation and T&D peak periods, thereby reducing the potential for DR to reduce customer demands at those times. In practice, the magnitude and direction of the impacts presented here could vary from this illustrative example, depending upon the DERs, their operating patterns, their location, and other factors.

Figure 5-4. Example of Interactive Effects on Energy Efficiency and Demand Response Resources



Interactive effects should be accounted for in BCAs for those instances where they are likely to have a material effect. Several resources are available to help address this issue, including ACEEE 2019b; ACEEE 2020; LBNL 2020b; RAP 2019a.

5.4.3 Enabling Other DER Types

Some DERs can make it easier or more cost-effective to adopt other types of DERs. One example is when a distributed storage resource is combined with DG to improve the latter's economics. A host can do this by storing excess PV generation during periods of low electricity costs and/or demand and discharging from the storage device during periods of high electricity costs or demand, as with the duck curve example discussed earlier (ACEEE 2020). Another example may entail an NWA where the utility requires a portfolio of multiple DER types (e.g., EE, DR, and storage) to meet a system need that could otherwise not be met cost-effectively by a single DER type.

Accounting for this enabling effect is more straightforward when both the enabled and enabling DER types are installed at the same time. In these cases, the cost-effectiveness analysis should account for the collective impacts of all DER types by recognizing the interactive effects on marginal system costs and on the magnitude of kWh or kW impacts from each DER type. (See Sections 5.4.1 and 5.4.2.)

Alternatively, there may be a situation where one DER type (the enabling DER) is installed prior to the other DER type (the enabled DER). In other words, the enabling DER has a "latent capability." For example, commercial and industrial lighting controls that are initially installed as part of an EE program could later be used as DR resources if that provides a greater economic opportunity.

One option to account for this potential is through probabilistic analysis:

- *Estimate the probability of the second DER type being installed.* This may be formed based on market research forecasting system-level DER growth expectations and/or more granular analyses on the propensity for individual customers to adopt specific DER types.
- *Forecast the expected impact of interactive effects.* Determine what the net impact would be from these DER types interacting. This should account for expectations around when the second DER types may be installed.
- *Calculate a probability-weighted net impact.* Multiply the results of the first two steps to derive a value to include in the cost-effectiveness analysis.

5.5 Behind-the-Meter Versus Front-of-the-Meter Impacts

All the DER types covered in this manual could be located BTM. Only DG (e.g., community solar, CHP, distributed wind) and energy storage (e.g., batteries, compressed air energy storage, and pumped hydro) can be located FOM. The principles, concepts, and guidance provided in this manual are generally applicable to both BTM and FOM DERs. This section discusses how the benefits and costs of DERs might vary depending upon whether the DER is located BTM or FOM.

The key differences between BTM and FOM DERs are (a) BTMs are typically owned and controlled by host customers to reduce their energy costs, while FOMs are typically owned and controlled by utilities to reduce utility system costs; and (b) FOM DERs do not have host customers, so they do not create host customer impacts. These differences have four implications:

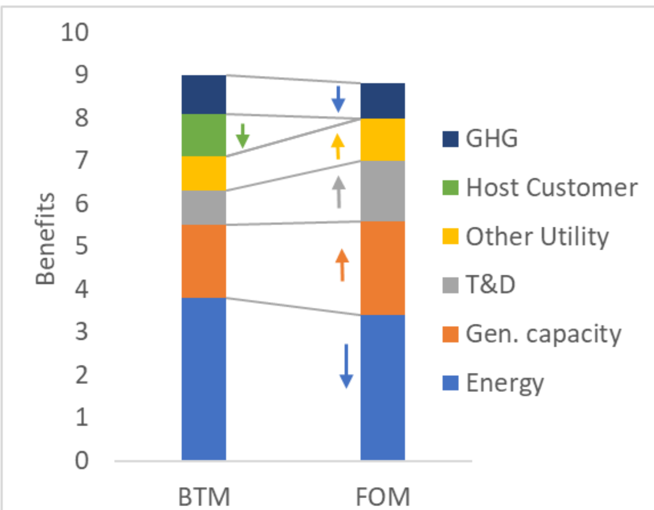
- BTM DER costs are sometime paid for by the host customer (e.g., DPV and storage), but FOM DER costs are typically paid for by the utility and eventually passed on to all utility customers.
- BTM DERs provide host customer benefits (e.g., host customer reliability) while FOM DERs do not.
- BTM and FOM DERs might be operated at different times due to the different economic incentives to the host customer versus the utility. For example, host customers with a non-coincident demand charge are likely to operate BTM storage at the time of the customer peak demand, which might not be the same time as the utility generation, transmission, or distribution peak periods. A more sophisticated rate design accounting for the time-varying nature of energy, capacity, transmission, and distribution costs, should incentivize a customer to operate BTM storage in a way that is more closely aligned with how a utility would operate a FOM storage.
- BTM DERs might be treated differently than FOM DERs in the operation of wholesale markets. While ISOs/RTOs have expanded opportunities for BTM DERs to participate in wholesale electricity markets, there may still be limitations on the ability of BTM DERs to provide and be compensated for certain wholesale market services (e.g., ancillary services).

Figure 5-5 presents a hypothetical example of how the benefits of a distributed storage resource might be different if it is located behind the meter versus in front of it. This example assumes that the BTM storage is operated by the host customer primarily to reduce bills in response to energy-based TOU rates, while the FOM storage is operated primarily to reduce generation and T&D peak period costs.

In this example:

- The energy and GHG benefits of the FOM DER are less than those of the BTM DER because the host customer operated the BTM storage to reduce their energy bill in response to TOU rates based on hourly energy costs.
- The generation capacity and T&D benefits of the FOM DER are greater than those of the BTM DER because the utility operated the FOM DER to reduce generation, transmission, and distribution peak costs.
- The host customer benefits do not exist for the FOM DER.
- The other utility benefits of the FOM DER are greater than those for the BTM DER because the utility is able to use the FOM storage to sell ancillary services into the wholesale electricity markets.[20]

Figure 5-5. Hypothetical Example of BTM Versus FOM for a Distributed Storage Resource



5.6 Air Emission Impacts

Determining the air emission impacts of a DER depends on at least two key factors. First, the BCA must clearly identify the time period for which to measure this impact (e.g., hourly, daily, monthly, etc.). The temporal granularity with which the BCA measures the impact could materially change how the DER is credited with air emission impacts relative to its actual impact. For example, if a BCA measures air emission impacts on a daily or monthly basis, the net impact will be averaged out across hours with varying air emission profiles, leading to a potential overstatement or understatement of the DER's air emission benefit/cost based on its actual performance.

Second, and related to the first factor, is understanding to the extent possible what the marginal emissions rate is of the resource being displaced by the DER's operation. For example, if a distributed PV resource operates at a time when the marginal resource is one that causes air emission costs, then the PV resource would be credited with the air emission benefit associated with displacing the emitting

[20] In practice, the magnitude and direction of the impacts presented here could vary from this illustrative example, depending upon the DERs, their operating patterns, their location, and other factors.

resource. Alternatively, if the PV resource is operating during a period of abundant PV production and the marginal resource is another PV resource, then there would be no corresponding air emission benefit since each resource has the same impact.

There are several analytical tools that can make probabilistic approximations of marginal emissions at hourly/diurnal/seasonal time and regional locational scales. For example, the U.S. Environmental Protection Agency (US EPA) offers the AVoided Emissions and geneRation Tool (AVERT) tool, which can be used to evaluate county, state, and regional emissions displaced at electric power plants by EE and renewable energy policies and programs. (See Appendix C.5).

Electricity system marginal emission rates can vary considerably over time as the mix of power plants and power plant dispatch changes over time. It is important that the system marginal emission rates account for expected changes to the electricity system over the course of the DER BCA study period.

Unlike generation resources that have an emissions rate associated with each kWh of generation, there is an additional layer of complexity for determining this impact for distributed storage resources and EVs (i.e., resources that can charge and discharge energy). For these resources, there are three factors affecting the direction and magnitude of the air emission impact: (1) the marginal emissions rate of the resource used to charge the resource; (2) the marginal emissions rate of the resource displaced by the discharge of the resource; and (3) the round-trip efficiency of the resource (i.e., energy losses associated with a charge-discharge cycle). The potentially significant intra- and inter-day variation in the marginal emissions rates requires particular attention to these first two factors to effectively determine the net impact on GHG and other air emissions.

5.7 Transfer Payments and Offsetting Impacts

Some DER BCA studies use the term "transfer payment" to describe the situation where one party experiences a cost and another a commensurate benefit (CA PUC 2001). This term has a specific meaning in economics, and is defined as follows:

> A transfer payment is a one-way payment of money for which no money, good, or service is received in exchange. Transfer payments commonly refer to efforts by local, state, and federal governments to redistribute money to those in need. Typical examples of transfer payments include government programs such as Social Security, Medicare, student grants, and unemployment compensation.[21]

In many cases, the transfer payments identified in DER BCAs are not the same thing as transfer payments as defined by economic theory. They are not a one-way payment of money for which no money, good, or service is received in exchange, and they are not driven by government social service programs.

Nonetheless, there are some situations in DER BCAs where a DER cost experienced by one party is exactly offset by a corresponding DER benefit experienced by another party. In some situations, it may be appropriate to exclude both impacts from a BCA because the net impact is zero, but in other cases it may not be appropriate to exclude both impacts because the two impacts do not truly offset each other.

In this manual, the term "off-setting impacts" is used to refer to the situation where a DER cost (or benefit) experienced by one party is exactly offset by a corresponding DER benefit (or cost) experienced by another party and it is therefore appropriate to exclude both impacts from the BCA.

[21] http://www.businessdictionary.com/definition/transfer-payment.html.

Offsetting impacts can be identified by considering two criteria. If both of these two criteria are met, then the benefits and costs in question are offsetting impacts:

- The DER cost in question is not a part of the total cost of acquiring the DER. Similarly, the DER benefit in question is not a part of the total cost of acquiring alternatives to the DER.
- Both the party incurring the cost and the party receiving the benefit are within the scope of the cost-effectiveness test being used.

Table 5-3 presents a summary of the DER impacts that are sometimes considered offsetting impacts. A "no" entry indicates that the impact is not an offsetting impact, while a "yes" entry indicates that the impact is an offsetting impact. (See Appendix F.)

Table 5-3. Potential Offsetting Impacts

BCA Test Used	Financial Incentives to Host Customers	DER Performance Incentives	Wholesale Market Price Effects	Tax Incentives
Utility Cost Test	No	No	No	No
TRC Test	Yes	No	No	No
Jurisdiction-Specific Test	Yes	No	No	Yes
Societal Cost Test	Yes	No	No	Yes

In this example, the JST is assumed to include host customer impacts but not taxpayer impacts.

Offsetting impacts should not be included in the BCA test because the benefit offsets the cost. Impacts that are not an offsetting impact should be included in the BCA test because the benefit does not offset the cost.

5.8 Variable Renewable Generation Impacts

Increasing levels of variable renewable generation can create new dynamics for the electricity grid, resulting in opportunities for DERs to either provide benefits by supporting the integration of these resources or cause additional costs by exacerbating system needs.

There are three primary factors to consider when determining the variable renewable generation impact of DERs:

- DR, distributed storage, and EVs (both in charge and discharge mode) can provide low-cost flexible resources that either take up excess demand or reduce demand to ease ramping needs on the system.
- In locations where substantial solar PV deployment leads to significant ramping of net load as the sun begins to set (the duck curve), there will be a greater need for resources to help mitigate the scale of this ramping need.
- If there are renewable curtailment requirements or periods of negative pricing due to an abundance of solar PV or wind generation relative to load, then a DER might be able to have additional value by shifting electricity grid consumption to these negative pricing hours. Conversely, DERs that operate during these periods might increase, rather than decrease, some of the utility system costs.

To effectively account for variable renewable generation impacts, a BCA should (a) account for the operational profile of the DER at a granular level (e.g., hourly), (b) account for intermittent renewable generation resources when determining utility system benefits, (c) account for ancillary services benefits related to system ramping from intermittent generation, and (d) account for periods with negative prices or when renewable resources are otherwise required to curtail operation.

5.9 Wholesale Market Revenues

Several types of DERs can participate in wholesale electricity markets in some parts of the country. Sometimes a host customer will participate directly in such markets, and sometimes DER aggregators will combine DERs from a number of host customers to participate in such markets. As DERs become increasingly common and wholesale markets become increasingly flexible, it is likely that DER will have expanded opportunities to participate in these markets over time.

When DERs participate in wholesale electricity markets, it is important to properly characterize the revenues from those markets in the DER BCA. In regions of the country with wholesale electricity markets, the energy, capacity, and ancillary services benefits should be included as utility system impacts. These benefits are typically based on the wholesale market prices of those services. Thus, the DERs' wholesale market benefits should be accounted for in all tests that include utility system impacts.

Since the energy, capacity, and ancillary services benefits of DERs are already included in the utility system benefits, there is no *additional* benefit associated with the revenues that host customers receive from wholesale markets. Therefore, revenues from DER participation in wholesale markets should not be included in most cost-effectiveness tests. If these revenues to host customers are included in cost-effectiveness tests, these benefits would be counted twice, which would violate the *Avoid Double-Counting Impacts* principle. The one exception is the PCT.[22] This test is explicitly designed to identify the impacts on host customers. The benefits for this test do not include the utility system benefits that are included in the other tests. Instead, the benefits include customer bill savings. Furthermore, the host customer revenues from wholesale markets are real benefits that are experienced by host customers in addition to the bill savings. In this case, it is appropriate to include wholesale market revenues as one of the benefits in the test. While this might appear to double-count the benefits of reducing wholesale market costs, it is nonetheless an accurate depiction of the impacts on host customers.

5.10 Free-Riders and Spillover Impacts

For jurisdictions that focus on net savings (i.e. savings net of free-rider and spillover effects), the decision of whether to include participant impacts in the jurisdiction's BCA has important implications for how to treat free-ridership and spillover effects. The treatment of net savings in BCA is particularly applicable to efficiency (See Appendix H).

If a jurisdiction *does not* include participant impacts in its cost-effectiveness test, rebates to free-riders should be considered as a cost. If the jurisdiction *does* include participant impacts in its cost-effectiveness test, cost-effectiveness analyses should not include free-rider costs because the participant's portion of the measure costs are part of the baseline (i.e., would have been incurred

[22] The PCT can provide useful information regarding the likelihood of customers adopting DERs, either on their own or with support from utility initiatives. This information can be helpful for designing DER initiatives, determining how much financial support to offer host DER customers, and forecasting future deployment of DERs. (See Appendix E.)

absent the program) and utility costs associated with rebates paid to free-riders is offset by a participant benefit (i.e., receipt of the rebate). By definition, jurisdictions focusing on net savings will not derive benefits from free-riders.

With respect to spillover effects, if a jurisdiction *does not* include participant impacts in its cost-effectiveness test, then its cost-effectiveness analyses should not include costs associated with spillover effects because all such costs would be borne entirely by spillover customers. If the jurisdiction *does* include participant impacts in its cost-effectiveness test, cost-effectiveness analyses should capture the entire measure cost because spillover customers incur this entire cost in the process of investing in efficiency measures. By definition, jurisdictions focusing on net savings will derive benefits from spillover effects.

Table 5-4 provides a summary of guidance on the inclusion, or not, of free-rider and spillover benefits and costs in cost-effectiveness tests for jurisdictions focused on net impacts.

Table 5-4. Summary of Economic Treatment of Free-Riders

Category	Free-Riders		Spillover	
	Costs	Benefits	Costs	Benefits
Utility system impacts	Increase	n/a	n/a	Increase
Participant impacts	Decrease	n/a	Increase	Increase (if applicable)
Other impacts	n/a	n/a	Increase (if applicable)	Increase (if applicable)
Total/Net impact	Increase only if test excludes participant impacts; otherwise no net effect	No effect under any test	No increase if test includes only utility system impacts; otherwise an increase	Increase under every test

5.11 Discount Rates

A discount rate is typically used in a BCA to convert future dollars into present value dollars. The choice of discount rate can have a significant impact on present value dollars and therefore on the results of the BCA. (See Appendix G.)

A 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.

Different economic actors can have differing discount rates, based on their own time preferences. Further, different resource types (DERs and other energy resources) have different costs of capital and different risk profiles, which are two of the factors affecting discount rates.

Despite these differences, a single discount rate is typically used for conducting a BCA. A single discount rate is typically applied to all the benefits and costs, even though the benefits and costs are associated with energy resources with different costs of capital and risk profiles. Similarly, a single discount rate is typically applied to a BCA, even though different parties affected by the resources in the BCA have different time preferences.[23]

There are three categories of discount rates typically considered for DER assessments: the utility's weighted average cost of capital (WACC), a discount rate reflecting an average customer time preference, and a societal discount rate. A fourth option is some combination of these three categories.

The choice of discount rate is a decision that should be informed by the jurisdiction's applicable policy goals. Further, the choice of discount rate should reflect the ultimate objective of the cost-effectiveness analysis. Therefore, the regulatory perspective should be used to determine the appropriate discount rate.

Based on the considerations described above, regulators should determine a discount rate that best reflects the jurisdiction's regulatory perspective, with input from stakeholders. Table 5-5 offers suggestions for how this determination might be made (See Appendix G).

Table 5-5. Considerations for Determining a Discount Rate

Consideration	If the answer is "yes"
Time Preference Considerations:	
Does the regulatory perspective suggest the same time preference as utility investors?	Choose a discount rate equal to the utility WACC.
Does the regulatory perspective suggest placing a higher value on long-term impacts than utility investors?	Choose a discount rate less than the utility WACC.
Does the regulatory perspective suggest the same time preference as that of all utility customers?	Choose a discount rate that is represents all utility customers on average.
Does the regulatory perspective suggest the same time preference as that of society?	Choose a societal discount rate.
Does the regulatory perspective suggest placing a lower value on long-term impacts than society does?	Choose a discount rate greater than a societal discount rate, or at the high end of the range of societal discount rates.
Risk Considerations (for use in situations where resource-specific risks are not accounted for in the BCA inputs):	
Will DERs result in a net reduction in risk relative to alternatives?	Choose a relatively low-risk discount rate, such as the societal discount rate.
Will DERs result in a net increase in risk relative to alternatives?	Choose a relatively high discount rate.

[23] Sensitivities can inform analysis of the effect of different discount rates. A single discount rate is typically used for any scenario or sensitivity.

PART III:
BENEFIT-COST ANALYSIS FOR SPECIFIC DER TYPES

Overview

This part of the manual includes separate chapters addressing each type of DER, including:

- energy efficiency,
- demand response,
- distributed generation,
- distributed storage, and
- electrification.

Each chapter includes a summary of key points; a description of the DER type; a summary of the utility system, host customer, and societal impacts; a discussion of the various factors that affect benefits and costs; and guidance on some key challenges of conducting BCAs for each DER type.

Each chapter discusses the benefits and costs of each DER type as if it were operated in isolation of the other DER types. This is partly for clarity and partly for readers and stakeholders who are interested in single-DER analyses. Part IV of the manual addresses issues that arise when multiple DERs are combined in different ways.

Each chapter includes a set of tables identifying the potential impacts of the DER type by utility system, host customer, and societal impacts. These tables are compiled across all the DERs in the Summary of this manual (pp xi–xii) to show the potential impacts across all the DER types.

6. ENERGY EFFICIENCY RESOURCES

This chapter describes the benefits and costs most relevant to energy efficiency (EE) resources. It identifies key factors that affect EE benefits and costs and provides guidance on addressing common challenges with EE cost-effectiveness analyses.

6.1 Summary of Key Points

- EE resources include technologies, services, measures, or programs that reduce end-use energy consumption by host customers, and that are funded by, promoted by, or otherwise supported on behalf of all electricity and gas utility customers.
- EE resources provide utility system benefits in the form of avoided generation and T&D costs, and other benefits such as reduced risk, and improved reliability and resilience of the capacity system. The costs typically include program administration costs, financial incentives, and utility performance incentives, where relevant.
- The temporal and locational benefits of EE can vary considerably across seasons and during different hours of the day, and as well as by the physical location on the energy distribution network.
- Some electric EE resources will reduce other fuel consumption resulting in other fuel benefits, while others will increase other fuel consumption resulting in other fuel costs.
- EE resources can create a variety of host customer NEIs, depending upon the technology and the host customer. The EE NEIs can include transaction costs, other resource Impacts, asset value, productivity, economic well-being, comfort, health & safety, and satisfaction/pride.
- EE resources can offer significant reductions in air emissions. As with all DERs, estimates of air emission impacts should account for the time period when the EE resource operates and the marginal emission rates of the utility system at that time.
- For the purpose of deciding which EE resources to invest in or otherwise support on behalf of utility customers, BCAs should be applied at the program, sector, and/or portfolio levels.
- Addressing the impacts of EE resources throughout their full effective useful life requires properly defining counterfactual (baseline) conditions for both savings and costs, particularly with respect to early-replacement projects.
- EE resources will typically create lost revenues. These might lead to increased rates, depending upon the magnitude of lost revenues, the magnitude of EE utility system costs, and the magnitude of utility system benefits. Rate impacts should not be included in BCAs, but should instead be accounted for in rate, bill, and participation analyses.

6.2 Introduction

For the purpose of this manual, EE resources include technologies, services, measures, or programs that reduce end-use energy consumption by host customers.[24] EE resources broadly include both (a) investments that provide the same level of (or better) service with lower energy use; and (b) conservation measures that may result in some reductions in amenity (e.g. removal of 2nd refrigerator, adjustment to thermostat setpoints through behavior programs, etc.).

Some efficiency measures and programs can offer at least the potential to be DR measures in the future. Examples include controllable "smart thermostats," variable speed drives on motors, and lighting controls. Such measures can both (1) enable customers' loads to be controlled through dispatchable DR in the future; and (2) enhance customers' ability to respond to price signals to lower demand during hours when energy is expensive and/or when there are capacity constraints on the system.

The fundamental BCA principles described in Chapter 2 can be used to identify the relevant benefits and costs for EE, as with all DER types. In many cases, identifying whether a particular benefit or cost is relevant to EE requires defining the specific EE technology and use case.

6.3 Benefits and Costs of Energy Efficiency Resources

The tables in this section summarize the full range of potential benefits and costs of EE resources (see Chapter 4 for definitions of impacts). Each impact is described as a benefit, a cost, or either, depending on the most common applications or use cases of this technology. There might be some less-common applications where a cost could be a benefit, or vice versa. The tables include notes on applicability that provide further explanation for those impacts that may be either a cost or benefit. Table 6-2 presents the impacts of EE on the gas utility system. All EE utility system impacts presented in these tables should be included in BCA tests. The remaining EE impacts presented in Table 6-3 (Host Customer) and Table 6-4 (Societal) should be included in BCA tests to the extent they are relevant to the jurisdiction's applicable policy goals (see Chapter 3).

[24] Some investments on the utility side of the meter that reduce customers' end-use consumption, such as conservation voltage regulation, are included in this definition.

Table 6-1. Potential Impacts of Energy Efficiency: Electric Utility System

Type	Utility System Impact	Benefit or Cost	Notes/Typical Applicability
Generation	Energy Generation	●	Always a benefit because EE reduces electricity generation
	Generation Capacity	●	A benefit because EE can reduce generation peaks; exceptions are EE measures that do not reduce system capacity requirements
	Environmental Compliance	●	A benefit because EE reduces electricity generation
	RPS/CES Compliance	●	Always a benefit because EE reduces electricity sales
	Market Price Response	●	Always a benefit in jurisdictions with wholesale energy and/or capacity markets
	Ancillary Services	●	Can be a modest benefit
Transmission	Transmission Capacity	●	A benefit because EE can reduce transmission peaks; same exceptions as for generation capacity
	Transmission Line Losses	●	Always a benefit because EE reduces transmission volumes
Distribution	Distribution Capacity	●	A benefit because EE can reduce distribution peaks; same exceptions as for generation capacity
	Distribution Line Losses	●	Always a benefit because EE reduces distribution volumes
	Distribution O&M	●	Always a benefit because EE reduces distribution volumes
	Distribution Voltage	●	A benefit for conservation voltage regulation programs
General	Financial Incentives	●	Always a cost, where relevant
	Program Administration Costs	●	
	Utility Performance Incentives	●	
	Credit and Collection	●	A benefit because customer savings make bill payment easier, especially for low-income programs
	Risk	●	Always a net benefit because EE is lower risk than supply-side resources
	Reliability	●	A benefit (if not already captured in avoided generation and/or avoided T&D categories)
	Resilience	●	A benefit where relevant – e.g. when large portions of a system need reconstruction, a history of efficiency investments reduces amount of capacity that requires reconstruction

● = typically a benefit for this resource type; ● = typically a cost for this resource type; ● = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

Table 6-2 presents the potential benefits and costs of EE on gas utilities and other fuel systems. Gas utility EE programs are most likely to reduce natural gas consumption. Electric utility EE programs can sometimes reduce and sometimes increase natural gas and other fuel consumption.

Table 6-2. Potential Impacts of Energy Efficiency: Gas Utility or Other Fuel System

Type	Non-Electric Energy System Impact	Gas Utility EE Programs	Electric Utility EE Programs that Affect Other Fuels	Notes/Typical Applicability
Other Fuel: Energy	Fuel and Variable O&M	🟢	🟢	Always a benefit for gas EE; electric EE programs that reduce other fuels will create a benefit[25]
	Capacity	🟢	🟢	A benefit for gas EE; exceptions are for measures that don't save in winter and/or during distribution system peak hours; electric EE programs that reduce other fuels create a benefit
	Environmental Compliance	🟢	🟢	Always a benefit for gas EE; electric EE programs that reduce other fuels create a benefit
	Market Price Response	🟢	🟢	
Other Fuel: General	Financial Incentives	🔴	○	Always a cost for gas EE; electric EE programs that reduce other fuels will not affect this impact
	Program Administration Costs	🔴	○	
	Utility Performance Incentives	🔴	○	A cost in jurisdictions that offer them; electric EE programs that reduce other fuels will not affect this impact
	Credit and Collection Costs	🟢	🟢	A benefit for gas EE, particularly for low-income programs; electric EE programs that reduce other fuels create a benefit
	Risk	🟢	🟢	Always a benefit for gas EE; electric EE programs that reduce other fuels create a benefit
	Reliability	🟢	🟢	A benefit for gas EE (exceptions the same as for those capacity described above); electric EE programs that reduce other fuels create a benefit
	Resilience	🟢	🟢	May be a benefit for gas EE; electric EE programs that reduce other fuels create a benefit

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

[25] Electric EE programs can sometimes indirectly increase the use of other fuels, e.g., when more efficient lighting produces less heat thereby requiring additional space heating. In these cases there will be a cost to the other fuel.

Table 6-3 presents the potential host customer impacts of EE (see Section 4.4).

Table 6-3. Potential Impacts of Energy Efficiency: Host Customer

Type	Host Customer Impact	Benefit or Cost	Notes/Typical Applicability
Customer	Host Customer Portion of DER Costs	🔴	Typically a cost; exceptions are when utility program pays the full measure cost (e.g. low-income programs) or there is no measure cost (e.g. behavior programs or disposal of extra appliances)
	Interconnection Fees	○	Not applicable for EE
	Risk	🟢	EE reduces exposure to future fuel price volatility
	Reliability	🟢	Lower loads enable back-up capacity (storage or generation) to be smaller and less expensive
	Resilience	🟢	Some EE measures may offer short-term resilience benefits (e.g. high levels of insulation allow customers to remain comfortable without heating fuel for longer periods)
	Tax Incentives	🟢	Potentially a benefit for those resources where they apply
	Host Customer NEIs	🟠	A benefit or cost depending on the NEI (see Section 6.4.4)
	Low-Income NEIs	🟢	A benefit; applies only to low-income EE programs

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

Table 6-4 presents the potential societal impacts of EE.

Table 6-4. Potential Impacts of Energy Efficiency: Societal

Type	Societal Impact	Benefit or Cost	Notes/Typical Applicability
Societal	Resilience	🟢	A benefit because improving resilience for the grid and host customers can also alleviate stress on a variety of public institutions during responses to catastrophes
	GHG Emissions	🟢	A benefit; magnitude depends on electric generation mix and any other fuel savings
	Other Environmental	🟢	
	Economic and Jobs	🟢	A benefit as EE resources are usually more labor intensive than electric and/or other energy supply
	Public Health	🟢	A benefit resulting from reduced environmental emissions; need to insure no double-counting of host customer NEIs and societal environmental impacts
	Low Income: Society	🟢	For low-income EE programs there can be societal benefits associated with environmental justice and community stability
	Energy Security	🟢	A benefit to the extent that efficiency reduces reliance on fuels with security concerns, e.g., imported fossil fuels

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

6.4 Key Factors that Affect Energy Efficiency Impacts

6.4.1 Technology Characteristics

EE differs from other DERs in various ways that have important implications for benefit-cost analysis. EE is an immensely diverse and modular resource: there are hundreds if not thousands of different types of EE measures, addressing numerous energy uses in a variety of different applications and buildings. They can also be promoted through a wide range of programs, implementation options, and market transactions. This modularity and diversity of EE means that comprehensive portfolios of EE programs can produce significant levels of load reduction in most every hour of the year.

Some EE measures can enable grid flexibility. For example, smart thermostats or networked lighting controls can enable dispatchable DR or facilitate customers' ability to respond to price signals. BCA for EE should consider the potential enabling of other DERs to meet system needs such as grid flexibility or other objectives.

6.4.2 Technology Operating Profile

The temporal and locational value of energy efficiency savings can vary considerably across seasons and during different hours of the day, and by the physical location on the energy distribution network. Thus, the temporal and locational attributes of EE have important implications for benefit-cost analysis, as these attributes will dictate the extent to which EE produces energy, generating capacity, and T&D savings.

The average hourly load shape of when energy savings occur will depend on the mix of efficiency measures in the efficiency program portfolio, the host customers to whom the measures are being promoted, the local climate, and a variety of other factors. For example, residential lighting savings will typically be higher in the winter than in the summer, a larger portion of residential cooling savings than of commercial cooling savings will occur in the evening, and industrial motor or process efficiency savings will tend to be more consistent across the hours of industrial operations than either residential or commercial energy savings.

6.4.3 Other Fuel Impacts

Table 6-2 presents the potential benefits and costs of EE on gas utilities and other fuel systems. Gas utility EE programs should always reduce gas consumption. Electric utility EE programs will often reduce other fuel consumption resulting in other fuel benefits. However, some electric efficiency measures can lead to increases in consumption of other fuels.

As shown in Table 6-2 non-electric cost savings resulting from efficiency improvements can extend beyond just commodity (i.e., fuel) savings. For example, when efficiency lowers natural gas consumption at times of gas system peak demand, it can help defer the potential for future capital investments to upgrade the gas transmission and/or distribution system infrastructure. There may be similar "capacity" savings associated with reduced infrastructure for distribution of petroleum products.

6.4.4 Host Customer Non-Energy Impacts

There can be a variety of host customer NEIs from EE investments. Although host customer NEIs can be either benefits or costs, depending on the EE measure, program, or host customer, the impacts in most efficiency program portfolios are primarily benefits.

Table 6-5 presents a summary of host customer NEIs that might potentially be created by EE resources. These impacts can sometimes be in the form of benefits and sometimes costs, depending on the most common applications for EE resources. The presence, direction, and magnitude of these impacts will depend upon many factors, including the EE program, the type of host customer (e.g., low-income, residential, commercial, industrial), and more.

Table 6-5. Potential Host Customer Non-Energy Impacts of Energy Efficiency

Category	Cost or Benefit	Examples
Transaction costs	● (cost)	– Application fees and processes
Other Resource Impacts	● (benefit)	– Reduced water consumption/cost – Reduced waste streams
Asset value	● (benefit)	– Equipment functionality/performance improvement – Equipment life extension – Increased building value – Increased ease of selling or leasing building
Productivity	● (benefit)	– Improved labor productivity – Reduced operation and/or maintenance (O&M) costs – Reduced spoilage/defects – Reductions in occupant turnover and/or increased occupancy rates in leased buildings – Impact of improved aesthetics, comfort, etc. on product sales
Economic well-being	● (benefit)	– Fewer bill-related calls to utility – Fewer utility disconnections and reconnections – Reduced foreclosures (especially for low-income host customers) – Fewer moves (especially for low-income host customers) – Other manifestations of improved economic stability (especially for low-income host customers)
Comfort	● (benefit)	– Thermal comfort – Noise reduction – Light quality
Health & safety	● (benefit)	– Improved well-being due to reduced incidence of illness—chronic (e.g., asthma) or episodic (e.g., hypothermia or hyperthermia) – Reduced medical costs (emergency room visits, drug prescriptions) – Fewer sick days (work and school) – Reduced deaths – Reduced insurance costs (e.g., for reduced fire, other risks)
Satisfaction/Pride	● (benefit)	– Contribution to addressing environmental concerns

● = typically a benefit for this resource type; ● = typically a cost for this resource type; ● = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

Specific examples of EE host customer non-energy benefits include:

- *Other Resource/Water savings:* certain EE measures, such as low-flow showerheads, pre-rinse spray valves for commercial dish cleaning, and efficient clothes washers save energy by reducing the amount of hot water (and therefore the amount of water) needed to meet customers' needs.

- *Asset value – building durability improvements:* for example, sealing and insulating attics can reduce or eliminate ice dams which occur when melting snow on a roof refreezes as ice at the edge of the roof, backing up other melting snow to the point where it can leak and damage the roof, walls, and other structural elements of the home.
- *Productivity benefits –*
    - *O&M cost savings:* for example, efficient LED lighting measures not only save electricity but are longer-lived than the standard/baseline lighting products they replace and, therefore, eliminate some future replacement costs that would otherwise be incurred.
    - *Business productivity and/or profitability improvements:* for example, higher quality LED lighting that can enhance aesthetics of retail product displays, ventilation efficiency improvements that can also improve indoor air quality and worker productivity, reductions in heating bills that can reduce vacancy rates for multi-family building owners, and reductions in industrial waste streams that can reduce energy consumption while lowering disposal costs.
- *Improvements to economic well-being:* for example, EE programs, particularly those targeted to low-income customers, can reduce stress associated with challenges in paying bills, reduce foreclosures, reduce the number of moves from one home or apartment to another.
- *Comfort improvements:* for example, sealing and insulating a home not only saves energy but improves the comfort of the home by reducing drafts and enabling more even distribution of heat.
- *Health and safety improvements:* for example, many home efficiency retrofit programs routinely test for, identify, and address problems such as back-drafting of combustion gases (including carbon monoxide) from fossil fuel-fired heating or water heating systems and mold problems associated with improper ventilation.

Examples of EE host customer non-energy costs include some losses of amenity (e.g., when second refrigerators are voluntarily removed and recycled), increased maintenance costs (e.g., for operating and maintaining CHP equipment), and aesthetic concerns.

For more information see: Tetra Tech 2011; Tetra Tech 2012; Skumatz 2014; NEEP 2017; and NESP 2019.

6.4.5 Air Emissions Impacts

EE resources can reduce air pollution emissions by reducing the amount of generation that fossil fuel-fired power plants will need to produce.

EE resources that affect multiple fuels can also have impacts on other fuels. For example, building envelope improvements can produce both electric cooling savings in the summer and natural gas (or other fossil fuel) heating savings in winter—with both forms of savings producing emission reductions.

As discussed in Chapter 5, air emission impacts should account for two important factors: (a) the time period for which the DER operates; and (b) the marginal emission rates of the utility system at the time when the DER operates.

The *Ensure Symmetry* principle requires accounting for both reduced and increased air emissions from EE resources, to the extent that they occur.

6.5 Common Challenges in Estimating EE Benefits and Costs

While it may be useful to understand cost-effectiveness at all four of these levels, when deciding which DERs merit utility acquisition they should be evaluated at the program, sector, or portfolio level.

There are a variety of challenges in estimating benefits and costs for EE resources. Fundamentally, conducting BCA for EE resources requires ensuring that the NSPM Principles are appropriately applied, in particular with regard to ensuring alignment with applicable policies and symmetrical treatment of relevant benefits and costs. These issues are addressed extensively in Chapters 2 and 3.

Other common issues covered in this section are: (1) the level of aggregation of EE impacts at which it is appropriate to assess cost-effectiveness; and (2) how to assess the impacts of early replacement measures (i.e., those installed prior to the end of the useful life of the existing equipment.) More detailed discussions of both of these issues, as well as treatment of fixed and variable costs, changing cost and/or benefit baselines, and both free-rider and spillover effects, is provided in Appendix H.

6.5.1 Assessment Level for Benefit-Cost Analysis

The cost-effectiveness of EE resources can be evaluated at several different levels of assessment. Assessments can focus on individual measures, individual customer-specific projects, individual programs combining multiple measures and/or projects, sectors (e.g., all residential or all business programs), and/or on a portfolio of programs across all sectors.

Cost-effectiveness analyses for EE resources should be applied – i.e., used to screen investments as worthwhile or not – at the program, sector, or portfolio levels. Applying cost-effectiveness results at the measure and project levels can have perverse implications, as further described in Appendix H. In some cases, it could reduce the overall net economic benefits of efficiency investments for the following reasons:

- A customer's interest in a non-cost-effective measure may be key to persuading the customer to install a package of measures that are cost-effective in aggregate;
- A customer's interest in a non-cost-effective measure may be key to the development of a relationship with the customer that can lead to installation of cost-effective measures in the future; and/or
- Installation of a non-cost-effective measure may be necessary in order to technically or safely enable the installation of other cost-effective measures.

Another disadvantage of assessing cost-effectiveness at the measure or project level is that it can be difficult to account for NEIs, hard-to-monetize impacts, or additional considerations at the measure level. Some NEIs, such as improved health and safety, are obtained through a package of multiple measures, and it is impractical to apply such impacts on each measure.

6.5.2 Early Replacement Measures

Many efficiency program portfolios include what are commonly called early replacement measures. These are measures in which an efficient new product is used to replace an inefficient existing piece of equipment that is still functioning and would not otherwise have been replaced—at least not until sometime in the future.

For example: an existing and functioning T12 commercial light fixture, that would normally not be replaced for another four years, is replaced this year through an efficiency program by a new LED light fixture with an assumed life of 12 years. In this example, the initial savings are a function of the difference in efficiency between the existing T12 and a new LED fixture, and the initial cost is the full cost of the LED fixture. However, the initial savings level would only last for the estimated four years of remaining life for the existing T12, and the installation of the LED fixture today would eliminate the cost that otherwise would have been incurred four years from now when the T12 would have been replaced absent the efficiency program.

A key to proper assessment of the cost-effectiveness of early replacement EE measures is to develop reasonable estimates of what would have occurred absent the EE program (i.e., the baseline)—both for savings and costs.

- *With respect to savings*, programs should employ what is commonly called a dual baseline. In the case of the T12 replacement example, that would mean (a) four years of savings equal to the difference in efficiency between the existing T12 and the new LED and then (b) eight years of savings equal to the (likely smaller) difference in efficiency between the new fixture that would have been purchased four years from now and the new LED installed today.
- *With respect to cost*, in jurisdictions that include participant impacts, the BCA needs to consider not only the upfront cost of the new LED fixture installed, but also the cost savings for the customer of not having to buy whatever new fixture they otherwise would have purchased four years from now. However, to align the baseline timeline with the efficiency investment timeline (i.e., to ensure an "apples to apples" assessment of the difference in costs) only a portion of the future cost that was eliminated should be treated as a cost savings. Put another way, if the baseline product that would have been installed four years from now would have had an expected life of 12 years, it is only appropriate to include eight years' worth of the cost savings (to align the cost comparison with the life of the LED measure installed today). See Appendix H for further details.

6.6 Lost Revenues and Rate Impacts

Lost revenues and potential rate impacts are not appropriate to include in cost-effectiveness analyses, and should instead be analyzed separately using rate, bill, and participation analyses. (See Section 2.3 and Appendix A.) In conducting BCAs, therefore, lost revenues should be identified so that they can be properly excluded from BCAs and properly included in rate, bill, and participation analyses.

In general, several key factors affect the extent to which DERs might create rate impacts:

- Increases in utility system costs will put upward pressure on rates.
- Reductions in utility system costs will put downward pressure on rates.
- Reductions in sales from DER resources will put upward pressure on rates.
- Increases in sales from DER resources will put downward pressure on rates.
- Rate design will affect the amount of lost or increased revenues created by the DER.

EE resources will typically increase utility system costs because of EE program costs, but they will reduce utility system costs by avoiding generation, transmission, and distribution costs (see Table 6-1).

EE resources will typically create lost revenues by (a) allowing host customers to reduce their energy bills by reducing their energy consumption; and (b) allowing host customers to reduce their energy bills by reducing demand charge payments, where such charges are in place.

Regulators and other stakeholders that are concerned about EE rate impacts might consider (a) conducting a long-term rate, bill, and participation analysis; (b) seeking EE program designs likely to mitigate equity concerns; (c) examining ways to expand customer participation, especially among low- and moderate-income customers; and (d) periodically reviewing impacts as EE programs are implemented.

7. DEMAND RESPONSE RESOURCES

This chapter describes the benefits and costs most relevant to demand response (DR) resources. It identifies key factors that affect DR benefits and costs and provides guidance on addressing common challenges with for DR cost-effectiveness analyses.

7.1 Summary of Key Points

- DR resources include a broad range of technologies, programs, and actions that can be used to control or manage electricity or gas demands, including dispatchable and non-dispatchable DR resources, DR for economic purposes, DR for reliability purposes, and time-varying rates.
- DR resources that result in load-shifting will create benefits during the targeted peak periods and costs during the periods to which loads are shifted.
- DR benefits will significantly depend upon the resource's operating profile, including how the resource will respond to price and dispatch signals.
- DR resources do not typically result in reduced consumption of other fuels. Some DR resources might increase the use of other fuels if the host customer relies upon some form of backup generation.
- DR resources provide avoided generation and avoided T&D benefits to the utility system, though in some cases load shifting may results in costs. Other benefits can include reduced risk and improved resilience. Costs typically include program administration costs, financial incentives and performance incentives, where relevant.
- DR resources can create several host customer NEIs, depending upon the technology and the host customer. These DR NEIs can include transaction costs, asset value, productivity, economic well-being, comfort, satisfaction/pride.
- DR resources can sometimes reduce air emissions by reducing the amount of fossil-fired generation or by shifting loads from high-emission periods to low-emission periods. DR resources can sometimes increase air emissions, for example, when DR resources rely upon fossil-fueled back-up power, or when DR resources shift loads from low-emission periods to high-emission periods.
- Many DR benefits will depend upon the counterfactual baseline for host customers.
- Some DR resources can provide benefits related to multiple grid services.
- DR resources will typically create lost revenues. These might lead to increased rates, depending upon the magnitude of lost revenues, the magnitude of DR utility system costs, and the magnitude of utility system benefits. Rate impacts should not be included in BCAs, but should instead be accounted for in rate, bill, and participation analyses.

7.2 Introduction

For the purposes of this manual, DR is a broad term that encompasses a variety of different technologies and programs that can provide a range of capabilities and services (e.g., shape, shift, shed, or shimmy). DR is a temporary and/or voluntary change in demand, and in that way differs from demand-focused energy efficiency measures which seek to obtain a permanent reduction in energy use during both peak and off-peak periods.

From the utility perspective, DR is a change in the power consumption by a customer that assists the utility to better match the demand for power with economic supply.

As the grid hosts an ever-expanding array of DR technologies, programs, and functionalities, the role and potential purposes of DR programs will also expand. Originally developed primarily to address coincident system demand peaks of relatively short duration, DR programs are evolving to address additional system needs, such as: mitigating demand fluctuations associated with EV charging; addressing rapid increases or decreases in demand associated with variable generation; ramping service to mitigate rapid-start requirements on generators, non-coincident peak reduction, locational peak reductions, and others.

The fundamental BCA principles described in Chapter 2 can be used to identify the relevant benefits and costs for DR, as with all DER types. In many cases, identifying whether a particular benefit or cost is relevant to DR requires defining the specific DR technology and use case.

Demand Response Services

DR resources include programs and actions taken to change energy use during specified time periods or under specific conditions, with the aim of cost-effectively altering customer usage and system demand.

Historically, the term "demand response" referred primarily to short-term reductions in electricity demand created at customer premises in response to utility price signaling or load control. From the utility perspective, DR is a change in the power consumption by a customer that assists the utility to better match the demand for power with economic supply. Because utility supply costs can rise dramatically during relatively brief peak demand periods, DR can be a cost-effective alternative to generation supply. Increasingly, DR can be a cost-effective solution to infrastructure upgrades and grid constraints as part of an NWS. (See Chapter 12.)

DR can also be used to increase consumption during particular time periods in order to make greater use of certain resources. For example, DR can be used to encourage customers to pre-cool a building in advance of a period of system peak demand. Finally, behavioral DR with technology advancements and paired with TOU rates can change customer energy usage behavior and can modify customer load profiles.

DR services have historically been characterized as applying to either load reduction, load-shifting, ancillary services, or load-shaping. A more recent DR taxonomy and analytic framework groups these services in categories to account for the increasing range of DR services and to facilitate comparisons between the cost and value associated with diverse and flexible loads. These core categories are: Shape, Shift, Shed and Shimmy (LBNL 2016, 1-1 to 1-2).

- *Shape* captures DR that reshapes customer load profiles through price response or on behavioral campaigns—"load-modifying DR"—with advance notice of months to days.

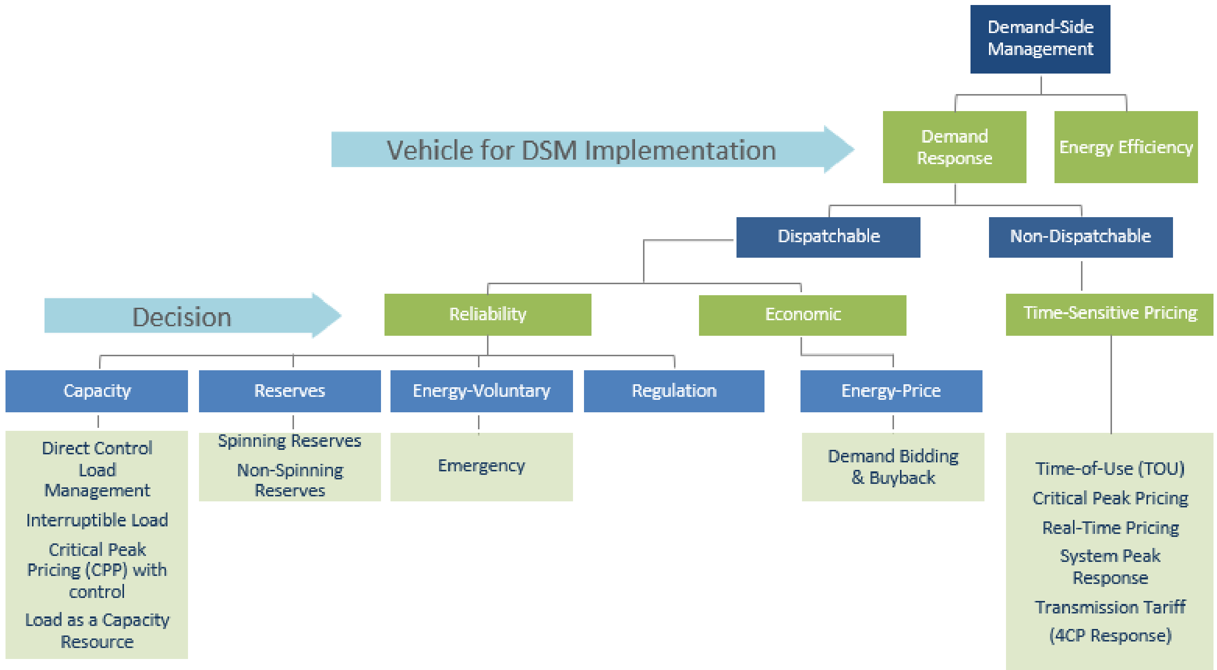
- *Shift* represents DR that encourages the movement of energy consumption from times of high demand to times of day when there is surplus of renewable generation. Shift could smooth net load ramps associated with daily patterns of solar energy generation.
- *Shed* describes loads that can be curtailed to provide peak capacity and support the system in emergency or contingency events—at the statewide level, in local areas of high load, and on the distribution system, with a range in dispatch advance notice times.
- *Shimmy* involves using loads to dynamically adjust demand on the system to alleviate short-run ramps and disturbances at timescales ranging from seconds up to an hour.

Demand Response Classifications

Figure 7-1 presents a classification of DR resources, differentiated by dispatchability (e.g., dispatchable versus non-dispatchable), purpose (e.g., economic benefits or reliability), and by types of program (e.g., TOU rates, critical peak pricing, direct load control) (NERC 2011):

- Dispatchable versus Non-Dispatchable: When used with DR resources, the term "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. Examples of dispatchable forms of DR include air conditioning switches, thermostats, or water heater programs that respond directly to a utility signal. The term "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.
- Program Purposes: DR resources may be designed and called upon for several purposes, and often provide multiple services simultaneously. Figure 7-1 shows the primary purposes served by various types of DR. The services provided by DR may include providing economic benefits by enabling a more cost-effectively scheduled energy mix and/or market purchases and by contributing to reliability by providing or reducing requirements for ancillary services and peak demand capacity, including during emergency or high-cost events. Non-dispatchable DR resources like time-varying rates can help shape loads to achieve economic, reliability, and customer-savings benefits.

Figure 7-1. Demand Response Classifications, Purposes, and Example Programs



Source: NERC 2011.

7.3 Benefits and Costs of Demand Response Resources

The tables in this section summarize the full range of potential benefits and costs of DR resources (see Chapter 4 for definitions of impacts). Each impact is described as a benefit, a cost, or either, depending on the most common applications of DR. In less-common applications, there may be cases where a cost could be a benefit, or vice versa. The tables include notes on applicability that provide further explanation for those impacts that may be either a cost or benefit.

Table 7-1 presents the potential benefits and costs of DR on the electric utility system, while Table 7-2 presents the impacts of DR on the gas utility system. All DR utility system impacts presented in these tables should be included in BCA tests. The remaining DR impacts presented in Table 7-3 (Host Customer) and Table 7-4 (Societal) should be included in BCA tests to the extent they are relevant to the jurisdiction's applicable policy goals (see Chapter 3).

Table 7-1. Potential Impacts of Demand Response: Electric Utility System

Type	Utility System Impact	Benefit or Cost	Notes/Typical Applicability
Generation	Energy Generation	🟠	A benefit for DR that reduces electricity generation, but load-shifting might result in costs
	Generation Capacity	🟢	A benefit because reduced system peak demand is frequently the primary objective of DR
	Environmental Compliance	🟠	A benefit for DR that reduces electricity generation, but load-shifting might result in costs
	RPS/CES Compliance	🟠	A benefit for DR that reduces electricity generation, but load-shifting might result in costs
	Market Price Response	🟢	A benefit since DR tends to target higher-priced supply in wholesale markets; depends on generation market operation
	Ancillary Services	🟢	A benefit due to load reductions during peak periods
Transmission	Transmission Capacity	🟢	A benefit due to load reductions during peak periods
	Transmission System Losses	🟢	A benefit due to load reductions during peak periods
Distribution	Distribution Capacity	🟢	A benefit due to load reductions during peak periods; however, circuit-level peaks are not always aligned with system peaks, and thus load-shifting to address system peaks could result in increased peak demand at the circuit or substation level, and *vice versa*
	Distribution System Losses	🟢	
	Distribution O&M	🟢	
	Distribution Voltage	🟢	A benefit when DR is used to manage voltage fluctuations on the grid
General	Financial Incentives	🔴	Always a cost, where relevant
	Program Administration Costs	🔴	Always a cost, where relevant
	Utility Performance Incentives	🔴	A cost (where jurisdictions have performance incentives)
	Credit and Collection	🟢	A benefit because customer savings make bill payment easier, especially for low-income customers
	Risk	🟢	A benefit due to reduced load during peak periods
	Reliability	🟢	A benefit due to better asset utilization of generation resources and enhanced grid flexibility
	Resilience	🟢	Potentially a benefit due to reduced restart load

🟢 *= typically a benefit for this resource type;* 🔴 *= typically a cost for this resource type;* 🟠 *= either a benefit or cost for this resource type, depending upon the application of the resource;* ○ *= not relevant for this resource type.*

Table 7-2 presents the potential benefits and costs of DR on gas utilities and other fuel systems. Gas utility DR programs are most likely to reduce gas consumption, but there may be examples of gas load-shifting programs that slightly increase gas consumption. Electric utility DR programs will typically increase other fuel consumption if they rely upon back-up generation from other fuels. Electric utility DR programs will rarely, if ever, reduce other fuel consumption.

Table 7-2. Potential Impacts of Demand Response: Gas Utility or Other Fuel System

Type	Non-Electric Energy System Impact	Gas Utility DR Programs	Electric Utility DR Programs that Affect Other Fuels	Notes/Typical Applicability
Other Fuel: Energy	Fuel and Variable O&M	🟠	🔴	Back-up generation or load-shifting from DR can increase costs and associated impacts of other fuels
	Capacity	🟢	🔴	
	Environmental Compliance	🟠	🔴	
	Market Price Response	🟠	🔴	
Other Fuel: General	Financial Incentives (e.g., rebates)	🔴	○	A cost for gas utility DR programs; not relevant otherwise
	Program Administration Costs	🔴	○	
	Utility Performance Incentives	🔴	○	
	Credit and Collection Costs	🟢	○	A benefit for gas utility DR programs; not relevant otherwise
	Risk	🟢	🔴	Back-up generation or load-shifting from electric utility DR can increase risk and reduce reliability and resilience of other fuels
	Reliability	🟢	🔴	
	Resilience	🟢	🔴	

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

Table 7-3 presents the potential host customer impacts of DR.

Table 7-3. Potential Impacts of Demand Response: Host Customer

Type	Host Customer Impact	Benefit or Cost	Notes/Typical Applicability
Host Customer	Host portion of DER costs	🔴	A cost when they exist
	Interconnection Fees	○	Not relevant for DR
	Risk	○	DR has little net risk impact on the host customer
	Reliability	🟠	A benefit or a cost, ddepending on electric and thermal ride-through capacity (e.g., the ability of the building to stay cool or warm during period of reduced electricity consumption); load-shifting or back-up generation might result in costs
	Resilience	🟠	
	Tax Incentives	🟢	A benefit, where applicable
	Host Customer NEIs	🟠	A benefit or cost depending upon the NEI (see Section 7.4.4)
	Low-income NEIs	🟢	A benefit for low-income DR programs only

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

Table 7-4 presents the potential societal impacts of DR.

Table 7-4. Potential Impacts of Demand Response: Societal

Type	Societal Impact	Benefit or Cost	Notes/Typical Applicability
Societal	Resilience	🟢	Potentially benefits due to reduced use during peak periods, especially where most inefficient and most expensive generators are on the targeted margin, or where DR is used to help integrate variable renewable generation; potentially costs if load-shifting and backup generation create environmental and public health costs
	GHG Emissions	🟠	
	Other Environmental	🟠	
	Economic and Jobs	🟢	
	Public Health	🟠	
	Low Income: Society	🟢	
	Energy Security	🟢	

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

7.4 Key Factors that Affect Demand Response Benefits and Costs

DR involves a change in load at a customer's premises, and thus the technical capabilities of the DR resource can be as diverse as the end-uses providing it. DR programs can also be designed to use a variety of communication technologies, incentive levels, customer engagement strategies, and performance requirements. All of these have important implications for cost-effectiveness.

DR programs are increasingly being implemented to address an expanding range of grid system conditions and issues. For example, DR programs aimed at *increasing* load in order to reduce renewable energy curtailment have been implemented, in addition to traditional DR programs focused on load reductions. Understanding and characterizing the problems that DR seeks to address is the first step in evaluating cost-effectiveness.

DR cost-effectiveness can also be profoundly impacted by whether a customer decides to simply reduce load, shift it to other hours, or use back-up generators to replace grid-supplied energy. Other important considerations for cost-effectiveness include the capabilities and performance characteristics of DR technologies themselves, as well as the ways that these resources are deployed by DR program managers.

7.4.1 Technology Characteristics

The type of benefits and costs provided by DR resources depend on two key technology characteristics: DR performance and DR predictability.

DR performance includes factors such as the speed, precision, and duration capabilities of the resource. For example, more traditional forms of DR (such as one-way water heating programs) may be called upon only to provide load reductions for capacity needs, while more advanced technologies with two-way communications (such as two-way grid-interactive water heaters) can be called upon to provide a broader range of services, including very precise frequency regulation, while also providing greater visibility to the DR program manager.

Understanding and characterizing the problems that DR seeks to address is the first step in evaluating cost-effectiveness.

Further, whether the DR resource can modulate load in both directions (both increasing and decreasing load) and the location of the resource on the system (for location-targeted reductions).

> The level of customer awareness and engagement will substantially impact the effectiveness of all programs.

DR predictability depends on the level of control the utility has over the DR resource. In some cases, a utility request to its customers to reduce usage during on-peak hours costs relatively little to the utility and also likely creates relatively small participant costs (since reduction in use is voluntary). This type of DR program is not very predictable, and reductions could occur almost anywhere on the system. In contrast, contract- and tariff-based DR programs offer precision in benefit and cost estimation, but also increased program costs in the form of higher incentives.

A residential thermostat control program provides a useful example. The level of peak demand reduction—and the predictability of that reduction—depends on whether the program is implemented through dispatchable control or utility messaging with voluntary, non-dispatchable customer response.

However, even dispatchable programs may incorporate customer override or opt-out provisions. If such provisions are widely exercised by host customers, the predictability and effectiveness of DR programs can be reduced. Prospective BCAs should account for this customer behavior, and proactive measures designed to reduce opt-outs may add to program costs (Navigant 2017; O'Leary 2016).[26]

In general, the level of customer awareness and engagement will substantially impact the effectiveness of DR programs. Building customer awareness often involves multiple and iterative education campaigns across multiple channels. Participation rates are a function of customer type, awareness, program choices, incentive rates, program complexity, hardware and software interactions and costs, and other factors—all of which could impact program costs and cost-effectiveness.

7.4.2 Technology Operating Profile

The cost-effectiveness of DR programs is a function of the load changes provided during the targeted time period, but also of any load changes in other hours. For example, participating DR customers during a summer peak event may have their air conditioners adjusted by a few degrees, but post-event may cause an unexpected spike in load induced by the DR event. In addition, customers who receive notice of impending super-peak pricing periods, for example, may pre-cool their buildings to ride through such events. It is conceivable that costs related to shifted load may overwhelm benefits of desired responsive behaviors. In every case, the extent to which customers respond and to which they shift load also affects (e.g., through pre-cooling) program cost-effectiveness.

7.4.3 Other Fuel Impacts

In some cases, the host customer response to a DR measure will be to rely on alternatives or substitute energy resources, such as self-generation. The simple case involves operation of a local dispatchable generator, such as a fossil-fueled reciprocating engine. Impacts associated with use of these resources, even if not under utility control, will affect DR program cost-effectiveness from a societal perspective (in terms of pollutants) and the host customer perspective (in terms of costs).

[26] Some argue that opt-out opportunities are a net benefit to program effectiveness because they increase enrollment and customer satisfaction.

7.4.4 Host Customer Non-Energy Impacts

Table 7-5 presents a summary of host customer NEIs that DR resources might potentially create. These impacts can sometimes be in the form of benefits and sometimes costs. The presence, direction, and magnitude of these impacts will depend upon many factors, including the DR program, the DR use case, the type of host customer (e.g., low-income, residential, commercial, industrial), and more.

Table 7-5 indicates whether each category of NEIs is typically a cost, a benefit, or either in most common applications for DR resources. The actual direction of the impact, however, may vary and should be determined on a case-by-case basis.

Table 7-5. Potential Host Customer Non-Energy Impacts of Demand Response

Category	Benefit or Cost	Examples
Transaction costs	● (red)	– Application fees and processes
Asset value	● (orange)	– Equipment functionality/performance improvement – Increased building value
Productivity	● (red)	– Labor costs and productivity – O&M costs
Economic well-being	● (green)	– Fewer bill-related calls to utility – Fewer utility shut-offs, reconnects
Comfort	● (red)	– Thermal comfort – Light quality
Satisfaction/Pride	● (green)	– Contribution to addressing environmental concerns

● (green) = typically a benefit for this resource type; ● (red) = typically a cost for this resource type; ● (orange) = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

7.4.5 Air Emissions Impacts

DR resources can sometimes reduce air emissions by reducing the amount of fossil-fired generation or by shifting loads from hours with high-emission resources on the margin to hours with low-emission resources on the margin.

DR resources can sometimes increase air emissions, for example, when DR resources rely upon fossil-fueled back-up power, or when DR resources shift loads from hours with low-emission resources on the margin to hours with high-emission resources on the margin.

As discussed in Chapter 5, estimates of air emission impacts should account for two important factors: (a) the time period for which the DER operates; and (b) the marginal emission rates of the utility system at the time when the DER operates.

The *Ensure Symmetry* principle requires accounting for both reduced and increased air emissions from EE resources, to the extent that they occur. (See Chapter 2.)

7.5 Common Challenges in Determining DR Benefits and Costs

7.5.1 Determining the Operating Profile

When assessing a DR program, the program classification, the type of technology deployed, program purpose, and the mechanisms used all help inform its cost-effectiveness. These component elements will ultimately characterize the operating profile that forms the basis for evaluation of the DR program.

The assessment of the DR program should be based on a detailed understanding of technologies to be used. Modeling of program impacts, program participation rates, and customer behavior over a range of future scenarios can support development of use-informed operating profiles.

7.5.2 Determining the Counterfactual Host Customer Baseline

Counterfactual customer baselines represent what the host customer load patterns would have been in the absence of the DR resource. DR resource savings are determined by comparing counterfactual baselines to the host customer load patterns with the DR in operation. It can sometimes be difficult to determine the counterfactual baseline for estimating DR savings.

Historical customer load patterns can be used to forecast a baseline, but historical customer data is of limited use. For example, customers might make significant changes to their buildings or facilities that affect load patterns; customers might install other DER types that will affect load patterns; or there might be structural shifts in the economy (e.g., a recession) that would affect customer load patterns.

Approaches and considerations to determining baseline usage include:

- Conduct data collection and analysis well in advance of the BCA for determining a host customer counterfactual baseline. This enables collection of baseline customer data and avoids introducing self-selection bias into the data. In addition, program developers can improve the accuracy of counterfactual estimates by undertaking customer research and segmentation analysis. Once programs are established, most DR programs have a large stock of non-participating customers that can be studied as a control group for establishing estimates of the counterfactual load patterns. However, self-selection bias should be recognized and mitigated in these control groups.
- Use of a control day or control customer within the program that does not receive an event signal, or ideally use of actual host customer load patterns on non-event days to construct a baseline. These options help eliminate self-selection bias concerns associated with using non-participant control groups.

Evaluation of data and results from peer utilities and programs can also help establish *a priori* estimates of DR savings. In some cases, measuring cost-effectiveness at the portfolio level may be more reliable, even if more general, than results obtained from program-by-program analysis.

7.5.3 Accounting for Provision of Multiple Services through Demand Response Programs

DR programs can provide value for multiple grid services. For example, operation of a DR program could provide either (a) wholesale generation capacity value in an organized market, (b) relief to heavily loaded distribution circuits, or (c) both. Accounting for these multiple impacts requires allocating benefits and costs across the different grid services, similar to the approach for allocating "joint and common" impacts. Accurately evaluating these shared impacts requires determining a reasonable and transparent method for allocating those benefits and costs—one that avoids double-counting or under-counting.

> Dispatchable DR measures allow for targeted application to various services. But they also raise tradeoff issues…

Dispatchable DR measures allow for targeted application to various services. But they also raise tradeoff issues, as with other DERs such as storage. Evaluating a DR resource requires attention to which services it can provide and how it will balance potential conflicts that prevent the resource from fully meeting all of its intended use cases (e.g., operation during one part of the day rendering the resource unavailable for another service later that day).

The process for determining the overall impact of DR programs that provide multiple services involves the following steps:

1. Evaluate the program and impacts as a whole. All benefits and all costs, wherever incurred or generated should be addressed on a cumulative basis to determine overall cost-effectiveness.
2. Select a consistent and reliable method for allocating program costs. Some benefits and costs may be directly allocable. For example, capacity market reservation fees for DR programs should be allocated to the generation market component of program costs.

In other cases, more general allocators may be appropriate. For example, if the implementing utility incurs generation costs that are 25 percent of total distribution revenue requirement and distribution capacity costs that represent 75 percent of those costs, these values can be used as a basis for allocating benefits and costs of the DR program. Ultimately, the allocation method should bear some relationship to costs avoided and incurred.

7.6 Lost Revenues and Rate Impacts

Lost Revenues and Rate Impacts of Demand Response in General

Lost revenues and potential rate impacts should not be included in cost-effectiveness analyses. Instead, DER lost revenues and rate impacts should be analyzed separately using rate, bill, and participation analyses (see Section 2.3 and Appendix A). In conducting BCAs, therefore, lost revenues should be identified so that they can be properly excluded from BCAs and properly included in rate, bill, and participation analyses.

In general, several key factors affect the extent to which DERs might create rate impacts:

- *Increases in utility system costs* will put upward pressure on rates.
- *Reductions in utility system costs* will put downward pressure on rates.
- *Reductions in sales* from DER resources will put upward pressure on rates.
- *Increases in sales* from DER resources will put downward pressure on rates.
- *Rate design* will affect the amount of lost or increased revenues created by the DER.

DR resources will typically increase utility system costs because of DR program costs, but they will reduce utility system costs by avoiding generation, transmission, and distribution costs.

DR resources will typically create lost revenues by (a) allowing host customers to reduce their energy bill by reducing, shifting, or shaping their energy consumption; and (b) allowing host customers to reduce their energy bill by reducing demand charge payments, where such charges are in place; and (c) providing host customers with bill credits for reducing demand, e.g., through a peak-time rebate program.

Where DR resources result in load shifts, DR lost revenues should be reduced by revenues generated during the period of increased usage.

Regulators and other stakeholders concerned about DR rate impacts might consider: (a) conducting a rate, bill, and participation impact analysis; (b) seeking DR program designs likely to mitigate equity concerns; (c) examining ways to expand customer participation, especially among low- and moderate-income customers; and (d) periodically reviewing impacts as DR programs are implemented.

Lost Revenues and Rate Impacts of Non-Dispatchable DR

DR programs based on non-dispatchable DR (e.g., time-varying rates) can increase bills for customers who are unable or unwilling to alter consumption during on-peak price periods. This can lead to reduced bills for customers who respond to price signals and increased bills for those who do not. These bill impacts may be the result of more efficient price signals that more accurately allocate costs according to customer consumption patterns, but they may also raise important equity concerns.

These impacts on customers who experience increased bills versus those that experience reduced bills should be assessed in a rate, bill, and participation analysis. In this case, the program participants (i.e., host customers) are those who respond to the non-dispatchable DR, and the non-participants are those who do not respond. Assessing DR program rate impacts, therefore, requires customer segmentation to understand which customers are able and willing to respond the most, and which customers respond the least. Such analyses should be periodically updated. This is because customer willingness and ability to respond to DR signals will likely evolve over time as grid modernization investments increase tools such as customer information portals and appliances with advanced controls become more common.

8. Distributed Generation Resources

This chapter describes the benefits and costs most relevant to distributed generation (DG) resources. It identifies key factors that affect DG benefits and costs and provides guidance on addressing common challenges with DG cost-effectiveness analyses.

8.1 Summary of Key Points

- Distributed generation includes a range of technology types, including DPV, CHP, distributed wind, distributed hydro, and distributed biomass.
- DG benefits and costs will depend upon whether the DG output is expected to only serve on-site load, only inject from the facility to the grid, or both.
- DG resources can either reduce or increase T&D costs, depending upon the hosting capacity on the utility system. Hosting capacity analyses can inform assessment of the direction and magnitude of these impacts and should account for potential changes to the system over the long run.
- Some DG resources, such as DPV, distributed wind, and distributed hydro, do not typically affect consumption of other fuels. Other DG resources, such as CHP and distributed biomass, can increase consumption of other fuels.
- Some DG resources, such as DPV, distributed wind, and distributed hydro, can reduce air emissions. Other DG resources, such as CHP and distributed biomass, might reduce or increase air emissions, depending upon the fuel used, the fuel avoided, and marginal emissions from the electricity grid.
- While DG resources sometimes require increased costs associated with the electricity they inject onto the grid, they do not create any additional costs associated with back-up services, supplemental services, or the host customer using the grid as if it were a battery.
- DG tariffs can create lost revenues, either by reducing host customer demand or by providing credits that reduce host customer bills. Lost revenues will not exceed what the host customer's bill would have been in the absence of the DG resource.
- Lost revenues from DG resources might lead to increased rates, depending upon the magnitude of lost revenues, the magnitude of DG utility system costs, and the magnitude of utility system benefits. Rate impacts should not be included in BCAs but should instead be accounted for in rate, bill, and participation analyses.

8.2 Introduction

For the purposes of this manual, DG resources include electric generation technologies interconnected to the distribution grid and operating at the distribution level. This generally means DG operates near a load, though some operate as stand-alone resources not close to a particular host customer's load. DG technologies include DPV, CHP, district heating and cooling, distributed wind, biomass and biogas facilities associated with landfills and agricultural operations, and others.

The fundamental BCA principles described in Chapter 2 can be used to identify the relevant benefits and costs for DG, as with all DER types. In many cases, identifying whether a particular benefit or cost is relevant to DG requires defining the specific DR technology and use case. For example, DG resources that never inject energy to the grid, but instead consume all generation on site, have different impacts from those that do inject energy back onto the grid.

8.3 Benefits and Costs of DG Resources

The tables in this section summarize the full range of potential benefits and costs of DG resources (see Chapter 4 for definitions of impacts). Each impact is described as a benefit, a cost, or either, depending on the most common applications of this technology. There might be some less-common applications where a cost could be a benefit, or vice versa. The tables include notes on applicability that provide further explanation for those impacts that may be either a cost or benefit.

Table 8-1 presents the potential benefits and costs of DG on the electric utility system, while Table 8-2 presents the impacts of DG on the gas utility system. All DG utility system impacts presented in these tables should be included in BCA tests. The remaining DG impacts presented in Table 8-3 (Host Customer) and Table 8-4 (Societal) should be included in BCA tests to the extent they are relevant to the jurisdiction's applicable policy goals (see Chapter 3).

Table 8-1. Potential Impacts of Distributed Generation: Electric Utility System

Type	Utility System Impact	Benefit or Cost	Notes, or Typical Applicability
Generation	Energy Generation	🟢	Typically benefits because DG reduces electricity generation and system peak demands
	Generation Capacity	🟢	
	Environmental Compliance	🟢	
	RPS/CES Compliance	🟢	
	Market Price Response	🟢	
	Ancillary Services	🟠	A benefit or a cost, depending upon DG technology and system conditions; magnitude of benefits and costs may change with deployment rate of DG on particular parts of the distribution system
Transmission	Transmission Capacity	🟠	A benefit or a cost because DG can increase or decrease transmission peak demand
	Transmission System Losses	🟢	A benefit because DG reduces transmission volumes
Distribution	Distribution Capacity	🟠	A benefit or a cost because DG can increase or decrease distribution peak demand
	Distribution System Losses	🟢	A benefit because DG reduces distribution volumes
	Distribution O&M	🟠	May add to or relieve congestion and grid management costs
	Distribution Voltage	🟠	A benefit or a cost, depending upon location-specific grid conditions
General	Financial Incentives	🔴	A cost to the extent they are relevant
	Program Administration Costs	🔴	
	Utility Performance Incentives	🔴	
	Credit and Collection Costs	🟢	A benefit because customer savings make bill payment easier, especially for low-income customers
	Risk	🟠	DPV reduces some system risks but adds complexity to system operations
	Reliability	🟠	Variable DG can support reliability or impose reliability costs at high deployment levels
	Resilience	🟢	Grids with DG should be easier to restore; islandable systems or systems with ride-through capacity may have faster restoration and reduced recovery times

🟢 *= typically a benefit for this resource type;* 🔴 *= typically a cost for this resource type;* 🟠 *= either a benefit or cost for this resource type, depending upon the application of the resource;* ○ *= not relevant for this resource type.*

Table 8-2 presents the potential benefits and costs of DG on gas utilities and other fuel systems. Gas utility DG programs might reduce or increase gas consumption, depending upon the facility and the fuel used. Some electric utility DG resources will not increase natural gas or other fuel consumption (e.g., DPV) but others can (e.g., natural gas-fired CHP).

Table 8-2. Potential Impacts of Distributed Generation: Gas Utility or Other Fuel System

Type	Non-Electric Energy System Impact	Gas Utility DG Programs	Electric Utility DG Programs that Affect Other Fuels	Notes, or Typical Applicability
Other Fuel: Energy	Fuel and Variable O&M	🟠	🔴	DG that uses gas or other fuels to generate electricity increases fuel use and associated impacts
	Capacity	🟠	🔴	
	Environmental Compliance	🟠	🔴	
	Market Price Response	🟠	🔴	
Other Fuel: General	Financial Incentives (e.g., rebates)	🔴	○	Typically costs for gas utility DR programs; not relevant otherwise
	Program Administration Costs	🔴	○	
	Utility Performance Incentives	🔴	○	
	Credit and Collection Costs	🟢	🔴	DG that uses gas or other fuels to generate electricity can create costs for these impacts
	Risk	🟢	🔴	
	Reliability	🟢	🔴	
	Resilience	🟢	🔴	

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

Table 8-3 presents the potential host customer impacts of DG.

Table 8-3. Potential Impacts of Distributed Generation: Host Customer

Type	Host Customer Impact	Benefit or Cost	Notes, or Typical Applicability
Customer	Measure Costs (customer)	🔴	Typically a cost
	Interconnection Fees	🔴	
	Risk	🟠	Reduced dependence on utility but may involve technology operating risk
	Reliability	🟢	Typically not relevant for renewable DG; potentially a benefit for CHP
	Resilience	🟢	
	Tax Incentives	🟢	Potentially a benefit, where relevant
	Host Customer NEIs	🟠	A benefit or a cost depending upon the NEI (see Section 8.4.4)
	Low-income NEIs	🟢	A benefit for low-income host customers only

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

Table 8-4 presents the potential societal impacts of DG.

Table 8-4. Potential Impacts of Distributed Generation: Societal

Type	Societal Impact	Benefit or Cost	Notes, or Typical Applicability
Societal	Resilience	●	Typically not relevant for renewable DG; potentially a benefit for CHP
	GHG Emissions	●	Renewable DG will typically reduce system emissions; CHP can also reduce system emissions depending upon fuel source and generation displaced
	Other Environmental	●	
	Economic and Jobs	●	Typically a net benefit
	Public Health	●	Renewable DG will typically offer benefits; CHP can also offer benefits depending upon fuel source and generation displaced
	Low Income: Society	●	A benefit, depending on siting and low-income participation
	Energy Security	●	A benefit for renewable DG; potentially a cost for non-renewable DG, depending on fuel source

● = typically a benefit for this resource type; ● = typically a cost for this resource type; ● = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

8.4 Factors that Affect Distributed Generation Benefits and Costs

8.4.1 DG Technology Characteristics

DG output typically has two possible outcomes:

- Generation that occurs during periods of on-site consumption will typically serve that load. In this manual, the term "load reduction" is used in the context of DG to refer to those periods when the DPV generation serves the host customer load.
- Generation that exceeds on-site consumption requirements will be injected onto the grid through the point of the customer's connection to the grid—typically at the meter. In this manual, the term "injection" is used in the context of DG to refer to the instantaneous injection onto the grid, even for very small time periods. Further, the term "excess generation" is used to refer to generation that is not used to offset host customer consumption from the grid over the course of that customer's billing period.[27] For example, for a customer with a monthly billing period, the excess generation will be the net effect of all the load reductions and injections that occur over that month.

Over a typical day, month, or year, some DG technologies might alternate frequently between generating for load reduction, injection to the grid, or both.

DG output that occurs during a time when the grid is down is often curtailed in order to prevent unwanted energizing of the grid for safety reasons. DG systems operating in an islandable/microgrid system may continue to serve load during grid outages.[28]

[27] In this manual the term "billing period" refers to the period used for reading customer meters and billing customers for their consumption. This is typically one month, but other options are possible.

[28] The Microgrid Institute identifies islandable microgrids as microgrids that are fully interconnected to a local utility grid and are capable of both consuming power from, and supplying power to, the utility grid. They can maintain some level of service during a utility outage. Operators remain tethered to the utility grid and switch seamlessly back and forth, drawing energy when they need it, and selling it back to the utility when they have surplus.

8.4.2 DG Technology Operating Profile

Characterizing DG benefits and costs should start with an assessment of whether the DG output is expected to serve only on-site load, is only injected from the facility to the grid, or both.

Serve on-site load only: Some DPV systems are sized so as to serve only on-site load and never inject energy onto the grid. The cost-effectiveness analysis for such systems should be generally the same as that for any load-modifying resource, such as energy efficiency.

Inject to the grid only: Some DPV systems might be installed by commercial developers for the purpose of only injecting onto the grid. These DPV system operators sell their output to the local utility, to a direct access customer, or to an ultimate customer through the utility and/or the wholesale power system. The cost-effectiveness analysis for these systems should be generally the same as that for a generator located on the distribution system.

Serve on-site load and inject to the grid: Many DPV systems both serve on-site load and inject energy onto the grid. These systems can simultaneously alternate between these modes instantaneously. This flexibility makes it difficult to distinguish between costs, benefits, and lost revenues. Different DG tariffs treat load reduction versus electricity generation differently; therefore, it is important to account for these mechanisms when identifying benefits, costs, and lost revenues of DPV resources. (See Section 8.5.1.)

8.4.3 Other Fuel Impacts

DG resources can have impacts on other fuel use, depending on the resource type:

- DPV systems typically do not have any impacts on non-electric fuels.
- Distributed wind and hydro resources typically do not have any impacts on non-electric fuels.
- CHP and district energy systems often rely on natural gas or biomass for primary fuel.
- Some DG resources rely upon biomass, biogas, or other fuels.

8.4.4 Host Customer Non-Energy Impacts

Table 8-5 presents a summary of host customer NEIs that might potentially be created by DG resources. These impacts can sometimes be in the form of benefits and sometimes costs. The presence, direction, and magnitude of DG NEIs will depend upon many factors, including the type of host customer (e.g., low-income, residential, commercial, industrial), and more.

Table 8-5 indicates whether each category of NEIs is typically a benefit, a cost, or either in most common applications for DG resources. The actual direction of the impact, however, may vary and should be determined on a case-by-case basis.

Table 8-5. Potential Host Customer Non-Energy Impacts of Distributed Generation

Category	Benefit or Cost	Examples
Transaction costs	● (cost)	− Application fees and processes, neighborhood association requirements
Asset value	● (benefit)	− Increased building value
Economic well-being	● (benefit)	− Fewer bill-related calls to utility − Fewer utility shut-offs, reconnects
Customer Empowerment & Control	● (benefit)	− Psychological benefit in the form of personal empowerment − Energy independence
Satisfaction/Pride	● (benefit)	− Contribution to addressing environmental concerns

● = typically a benefit for this resource type; ● = typically a cost for this resource type; ● = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

8.4.5 Air Emissions Impacts

Many DG systems installed in the United States are DPV systems, powered by emissions-free solar energy. For these systems, reductions in environmental compliance costs can create benefits to the utility system and reductions in emissions can create benefits to society. For other kinds of DG, such as gas-, biomass-, gasoline- or diesel-powered generators, there may be either increased or reduced air emissions depending upon the DG fuel, the displaced fuel, the DG operating patterns, and more.

The location and effects of air emissions may vary among DG technologies and according to operating profiles. Biomass-fueled DG may avoid upstream utility emissions and, for example, methane emissions from anaerobic digestion of wastes. However, these systems typically generate electricity through combustion of the biomass fuel, producing local emissions that have local incremental impacts.

CHP systems that operate efficiently on methane gas may also avoid air emissions by displacing large-scale generation. While CHP systems produce local emissions, the net system-wide efficiency and emissions reductions benefits may yield a net benefit for this type of DG.

The *Ensure Symmetry* principle requires accounting for both avoided and incremental emissions in order to accurately account for the emissions impacts of DG systems that produce emissions.

8.4.6 Cumulative Effects: The Duck Curve

Unless coupled with energy storage systems, all PV systems in a particular area will start and stop generating in correlation with available sunlight. Large quantities of PV, including both utility-scale and DPV, can therefore have large cumulative impacts on the grid associated with the decline of solar generation as the sun sets. This often occurs at the time when residential system demand is in or approaching the period of peak demand and can create a rapid rise in system-wide energy demand and an urgent need for load-following resources. The effect, which when plotted on a graph appears like the silhouette of a duck, may be a source of increased demand for generation, capacity, and ancillary services. Even if the effect is not significant across an entire grid system, clustering of DPV systems could create the problem at smaller scales.

The duck curve effect of PV systems might impose other costs on the electricity system to respond to the rapid rise of resources needed to meet the declining solar resource. If this effect is expected to be large enough to make a material difference in the BCA results, then these additional costs should be accounted for in the BCA. Any such estimates of these costs should account for other resources that are likely to be available mitigate the costs, including DR, storage, and resources providing ancillary services.

8.5 Common Challenges in Determining DG Benefits and Costs

8.5.1 Implications of DG Tariffs on Lost Revenues

Many jurisdictions have created DG tariffs that determine how a host customer will be compensated for DG output. These DG tariffs are designed in many different ways, and the specific design of a DG tariff will affect the amount of lost revenues created by the DG resource.

The diversity and complexity of DG tariffs raise two important BCA questions. To what extent does the DG tariff used in the jurisdiction create lost revenues? To what extent does the DG tariff used in the jurisdiction create utility system costs?[29]

DG Tariff Design Options

For BCA purposes it is useful to describe DG tariffs as falling into two categories:

- *Net billing* approaches, where a portion of the DG output is used to offset the host customer electricity consumption, while the remaining output (i.e., the excess generation) is compensated at a specific compensation rate (NREL 2017a): This approach can be applied using traditional meters and therefore has been widely used to date. Net billing approaches can include traditional net metering, where the compensation rate for the excess generation is equal to the host customer retail rate. They can also include alternative rates to compensate excess generation.[30]
- *Buy-all/sell-all* approaches, where all the DG output is compensated at a certain rate (PNNL 2018): In these cases, the DG output does not offset the host customer's electricity load. This approach requires meters that measure the output of the DG.

Both net billing and buy-all/sell-all mechanisms can offer a variety of compensation rates. The compensation rates can equal the host customer's retail rates (in the case of net metering); they can equal utility system avoided costs; they can equal a rate that is designed to cover all or some of the cost of installing and operating the DG; or they can be based on something else. Further, both net billing and buy-all/sell-all options can be used for community or virtual solar projects.[31]

[29] Any costs created by DG resources should be included in a DG BCA, but lost revenues, and the rate impacts that they create, should be addressed separately in a rate, bill, and participation analysis. (See Section 2.3 and Appendix A.)

[30] Some studies describe net metering as a separate category from net billing (PNNL 2018). In this manual the term "net billing" is used to describe net metering as well as net billing. Both types of tariffs have the same general design where a portion of the DG output is used to offset the host customer electricity load, and the excess generation is compensated separately. Net billing and net metering typically differ (a) in the compensation rate and (b) in the period when customer consumption and DG output are netted.

[31] Community or virtual solar projects are when a solar facility is not installed on a host customer premises but is instead installed externally and shared among subscribers. Subscribers typically receive credits on their electric bill for energy produced by their share of the solar facility.

For both net billing and buy-all/sell-all tariffs, participating customers are typically offered bill credits as compensation for the DG output. In the case of net billing, the bill credits apply to only the excess generation whereas for buy-all/sell-all, the bill credits apply to all of the DG output.

One of the key design features of net billing tariffs is the treatment of excess generation.

One of the key design features of net billing tariffs is the treatment of excess generation. Excess generation is typically determined over the billing period because net billing tariffs rely upon traditional meters that cannot distinguish excess generation at a more detailed level. In most net billing tariffs, any excess generation in one billing period is used to create a bill credit to offset the host customer bill in the following billing period. These bill credits can roll forward from one billing period to the next until they are used up. Many jurisdictions place a limit on how long the bill credits can be rolled forward (i.e., they apply a netting period over which the excess generation will be compensated).[32]

Billing credits remaining at the end of the netting period can be treated different ways. For example, sometimes the host customer can choose to provide extra DG bill credits to other utility customers; sometimes the value of remaining bill credits is paid directly to host customers; and sometimes the remaining bill credits are simply retired (i.e., they are not used for any purpose).

Identifying Lost Revenues and Utility System Costs

A few key considerations can help identify the extent to which DG tariffs might create lost revenues or utility system costs.

First, lost revenues are created two ways. Lost revenues are created when the host customer's demand is met by the DG output, thereby reducing the net amount of electricity that the customer consumes and is billed for. Lost revenues can also be created from the bill credits generated as a result of the DG tariff. These bill credits allow host customers to pay lower bills in just the same way that reduced consumption does. Since lost revenues can be created from either reduced host customer electricity load or from the bill credits, it is not necessary to determine the extent to which a DG resource offsets a customer's load or exports electricity to the grid in order to estimate lost revenues.

Second, lost revenues should be measured relative to the total electricity bill that the host customer would have experienced if not for the DG output (i.e., the counterfactual host customer bill). It is best to determine the counterfactual bill over the full netting period because this will capture the effects of rolling credits across billing periods. Further, lost revenues can never exceed the host customer's counterfactual bill over the full netting period. In other words, revenues can only be considered lost if they would have existed in the counterfactual case.

Utility system costs are created only if there is some increase in utility revenue requirements.

Third, utility system costs are created only if there is some increase in utility revenue requirements. If a DG tariff results in an increase in utility revenue requirements, then there will be a utility system cost resulting from that tariff. If not, then there will not be any costs created by the DG tariff.[33]

Fourth, if the total compensation paid for the DG output exceeds the host customer counterfactual bill, i.e., exceeds the lost revenues, then the difference might create a new utility system cost. Whether this difference

[32] In this manual, the term "netting period" refers to the period over which customers are allowed to carry forward their billing credits. This is typically one year, but other options are possible.

[33] This point refers only to utility system costs created by the DG tariff compensation mechanism. Other utility system costs, such as those indicated in Table 8-1, can be created by the DG resource.

creates a new utility system cost depends upon how the DG bill credits are treated at the end of the netting period, as described below.

All T&D impacts created by DG resources should be accounted for in cost-effectiveness analyses.

These considerations lead to the following conclusions:

- Lost revenues from DG resources will equal the amount of DG output times the compensation rate for the DG output.
    - For buy-all/sell-all DG tariffs, the compensation rate for this purpose is simply the compensation rate offered for the DG output and used to create bill credits.
    - For net billing DG tariffs, the compensation rate for this purpose has two components. The DG output that is used to reduce the host customer load is compensated at the host customer retail rate, while the excess DG output is compensated at the excess generation compensation rate. For net metering these two compensation rates will be the same, but for other forms of net billing they will be different.
- Lost revenues from DG resources will not exceed the host customer counterfactual bills over the DG tariff netting period.
- If a DG resource is expected to be compensated at an amount that exceeds the lost revenues, then the implications of this outcome will depend upon how any such difference is treated by the utility at the end of the netting period:
    - If the host customer is allowed to provide any excess bill credits to other utility customers, then those bill credits will create lost revenues by reducing the recipient's bills.
    - If the value of the remaining bill credits is provided to the host customer in the form of a payment, then this payment represents a new incremental utility system cost.
    - If the bill credits remaining at the end of the netting period are simply retired, then they will not create lost revenues or utility system costs.

To date, few jurisdictions have established DG tariffs that allow host customers to be paid for bill credits that exceed their counterfactual bill. Thus, there are few circumstances where a DG tariff would create a utility system cost. In most cases, the lost revenues will be equal to the DG output times the compensation rate(s) for that output, with a cap equal to the magnitude of the host customer's counterfactual bill.

8.5.2 Accounting for Transmission and Distribution Impacts

DG resources have the potential to reduce T&D costs because they are sited close to customer load and result in less electricity being transmitted from centralized generation sources to the host customer. On the other hand, some DG resources have the potential to increase T&D costs when the level of interconnected DG exceeds the hosting capacity of the system.

In addition, any single DG facility is not likely to have much impact on T&D costs on its own, particularly small DG facilities, and particularly when DG facilities are installed on systems with excess T&D capacity. However, when multiple DG facilities are installed over time, they might have significant positive or negative effects on T&D costs. In some utility systems, new DG resources might have very little impact on T&D costs for several years, but then the system might reach a tipping point where system upgrade costs become required.

These factors create challenges for determining the magnitude and the direction of DG resources' impacts on the T&D system.

All T&D impacts created by DG resources should be accounted for in cost-effectiveness analyses, as with any DER type (see Section 2.3 and Section 3.3). The magnitude and direction of these impacts can vary across utility systems, depending upon the hosting capacity on the system and any changes to hosting capacity over time. Therefore, the utility hosting capacity should be considered when determining whether new DG resources will likely reduce or increase distribution system costs. The likelihood of such impacts will be greater on circuits that have been identified as approaching maximum capacity or that are experiencing unusually high load growth. Marginal cost of service studies can also be used as a preliminary tool for assessing impacts. In addition, tracking patterns of DG development may help prioritize hosting capacity analyses.

BCAs should include study periods that are long enough to capture the full long-run costs and benefits of the DERs, consistent with the *Conduct Forward-Looking, Long-term, Incremental Analyses* principle (see Section 2.3). This may require study periods that are 20 or 30 years long. Study periods this long allow for an assessment of the long-run impacts on the utility system hosting capacity. If the hosting capacity is expected to be sufficient in the short run but insufficient in the long run, then that expectation should be factored into the determination of the DG effects on distribution system costs.

Hosting capacity analyses should account for estimated deployment levels of DG resources over time. They should also account for estimated deployment levels of other DER types, as well as other factors such as load growth and distribution system upgrades that would occur regardless of DG deployment.

8.5.3 Accounting for Grid Services to the Host Customer

Under current U.S. federal law and regulation, substantially replicated and applicable in most U.S. states, utilities are obligated to provide back-up and supplementary power services and rates to certain qualified facilities. This includes distributed qualified facilities. This raises the question of whether the back-up or supplementary power services provided to DG host customers represents an impact that should be included in a BCA.

Similarly, when DG resources inject electricity onto the grid it raises the question of whether host customers benefit from using the grid essentially as a battery to allow them to take advantage of their excess generation, and whether this effect represents an impact that should be included in a BCA.

All distribution upgrade costs created by DG resources, or any DER, should be accounted for in cost-effectiveness analyses (see Section 2.3 and Section 3.3). Regarding the two questions raised above:

- If the utility has to incur incremental costs in order to enable a customer to inject DG generation onto the grid, then those costs should be accounted for in the interconnection or distribution system upgrade costs.
- If the DG injections do not require any such incremental costs, then there are no costs associated with back-up services, supplemental services, or the host customer using the grid as if it were a battery.

8.5.4 Community Solar Projects

Community solar projects allow customers to subscribe to a designated share of the output of a solar system sited remotely from their premises. Community solar projects offer the advantage of allowing customers that do not have adequate facilities for siting DPV to benefit from DPV projects. They can be especially useful in supporting low-income customer participation in DPV.

The Absence of a Host Customer Load

Community solar projects differ from other types of DPV because there is no host customer whose load would be reduced by the community solar projects. This raises the question of how the lack of a host customer load affects the lost revenues and utility system costs created by the community solar DG tariff. If there is no host customer load to offset, does the community solar project create lost revenues for the utility?

Community solar projects typically create bill credits that are provided to the participants in the program. These credits are then used to reduce the participants' bills. These reduced bills result in lost utility revenues in the same way that reduced bills from reduced customer load create lost revenues. Therefore, the lost revenues from community solar projects will be equal to the project's output times the community solar compensation rate. These lost revenues should not be included in a BCA but should be accounted for in rate, bill, and participation analyses. Community solar projects will not create utility system costs as a result of the DG tariff.[34] (See Section 8.5.1.)

Avoided Transmission and Distribution Costs

Unlike on-site DPV, remote solar projects use the grid to transmit the electricity they produce. This raises the question of whether they can avoid the transmission or distribution costs that on-site DPV facilities can avoid.

DERs can either increase or decrease utility system infrastructure costs, depending upon the loading characteristics and hosting capacity available on the distribution system. As with any type of DER, community solar projects should account for the distribution system hosting capacity in order to determine the actual impact the facility will have on the grid. (See Section 4.2.)

Some DERs will have different impacts depending upon the location of the DER on the distribution grid, and BCAs should attempt to account for this locational value wherever it is likely to have a material effect on the BCA results. There may be some locations where community solar projects increase infrastructure costs and some locations where it decreases them. (See Section 5.3.)

8.6 Lost Revenues and Rate Impacts

Lost revenues and potential rate impacts should not be included in cost-effectiveness analyses. Instead, DER lost revenues and rate impacts should be analyzed separately using rate, bill, and participation analyses. (See Section 2.3 and Appendix A.) In conducting BCAs, therefore, lost revenues should be identified so that they can be properly excluded from BCAs and properly included in rate, bill, and participation analyses.

In general, several key factors affect the extent to which DERs might create rate impacts:

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[34] Community solar projects can create other utility system costs, such as those presented in Table 8-1.

- *Increases in utility system costs* will put upward pressure on rates.
- *Reductions in utility system costs* will put downward pressure on rates.
- *Reductions in sales* from DER resources will put upward pressure on rates.[35]
- *Increases in sales* from DER resources will put downward pressure on rates.
- *Rate design* will affect the amount of lost or increased revenues created by the DER.

DG resources will typically increase utility system costs because of grid upgrade costs or program administration costs, but will reduce utility system costs by avoiding generation, transmission, and distribution costs (see Table 8-1).

DG resources will typically create lost revenues by (a) allowing host customers to reduce their energy bill by reducing their energy consumption; (b) allowing host customers to reduce their energy bill by reducing demand charge payments, where such charges are in place; and (c) providing host customers with bill credits for excess DG output. The lost revenues from DG resources will depend upon the DG tariff in effect, among other factors. (See Section 8.5.1.)

Regulators and other stakeholders that are concerned about DG rate impacts could consider the following: (a) conduct a long-term rate, bill, and participation impact analysis; (b) seek and implement DG tariffs likely to mitigate equity concerns (e.g., by keeping compensation rates relatively low); (c) seek ways to expand customer participation through programs like community solar projects, especially among low- and moderate-income customers; and (d) periodically review impacts as DG deployment rates increase. (Consumers Union 2016.)

[35] Some DG tariffs create a different dynamic regarding rate impacts. Some DG tariffs provide customers with bill credits for the DG output, which can be rolled over across billing periods or be used to support virtual or community solar programs. These bill credits are sometimes a better indication of DG lost revenues than reduced sales from the DG resource. (See Chapter 8.)

9. DISTRIBUTED STORAGE RESOURCES

This chapter describes the benefits and costs most relevant to distributed storage (DS). It identifies key factors that affect distributed storage benefits and costs and provides guidance on addressing common challenges with distributed storage cost-effectiveness analyses.

9.1 Summary of Key Points

- Distributed storage resources include lithium-ion batteries, lead-acid batteries, and thermal storage such as electric water heaters.
- Perhaps more than any other DER type, the benefits and costs of distributed storage resources will depend significantly on the use case of the storage device.
- The use case for a storage device will depend upon many things, such as the technology charging and discharging capabilities, the host customer rate design, whether the operation is controlled by the host customer versus the utility, and more.
- Like other DERs, the ability of distributed storage resources to “stack” multiple benefits can significantly affect its benefits and costs. However, evolving wholesale electricity market rules combined with the inability of distributed storage to sustain an indefinite charge/discharge requires consideration of potential tradeoffs between different impacts.
- Distributed storage resources can either reduce or increase air emissions, depending upon the use case for the storage device, the marginal emission rates during charging times, the marginal emission rates during the discharging time, and the round-trip efficiency of the storage resource.
- The benefits of distributed storage will depend upon how it will balance potential conflicts that prevent it from fully meeting all of its intended use cases (e.g., operation during one part of the day rendering the resource unavailable for another service later that day).
- Distributed storage resources will typically create lost revenues as a result of the ultimate bill savings to host customers. These might lead to increased rates, depending upon the magnitude of lost revenues, the magnitude of distributed utility system costs, and the magnitude of utility system benefits. Rate impacts should not be included in BCAs, but should instead be accounted for in rate, bill, and participation analyses.

9.2 Introduction

For the purposes of this manual, distributed storage resources include lithium-ion batteries , lead-acid batteries, and thermal storage such as electric water heaters.[36] Storage technologies like pumped hydro

[36] EVs can also act as a storage resource. These are addressed in Chapter 10.

and compressed air tend to be connected at the transmission, not the distribution, level and are therefore not considered distributed storage.

It is imperative to define the storage device use case, i.e. how it will be implemented and operated, to determine the relevant benefits and costs. Any cost-effectiveness evaluation of distributed storage should consider both the advantages it provides (e.g., dispatchability) and some of the inherent limitations of the technology (e.g., an inability to indefinitely charge/discharge energy; the losses involved in roundtrip efficiency; etc.).

> It is imperative to define the use case—i.e. how the resource will be implemented and operated—for the distributed storage resource to determine the relevant benefits and costs.

There are many factors affecting a storage resource's cost-effectiveness, including resource location, resource ownership and control, the resource's expected operating profile, and considerations around interconnection. Taken together, these factors will influence not only which impacts are relevant, but also whether they amount to a benefit or cost.

This chapter primarily focuses on distributed storage resources that are located behind a host customer's meter (i.e. coupled with load). One key difference between BTM and FOM storage is that, in general, BTM storage can provide a greater number of distinct benefits to host customers than FOM storage. For example, FOM storage resources cannot provide bill management (e.g., demand charge reduction or TOU rate arbitrage) benefits for customers (see Chapter 5). Another key difference is that FOM storage may offer greater economies of scale than BTM storage.

9.3 Benefits and Costs of Distributed Storage Resources

The tables in this section summarize the full range of potential benefits and costs of distributed storage resources (see Chapter 4 for definitions of impacts). Each impact is described as a benefit, a cost, or either, depending on the most common applications of this technology. There might be some less-common applications where a cost could be a benefit, or vice versa. The tables include notes on applicability that provide further explanation for those impacts that may be either a cost or benefit.

Table 9-1 presents the potential benefits and costs of storage on the electric utility system, while Table 9-2 presents the impacts of storage on the gas utility system. All storage utility system impacts presented in these tables should be included in BCA tests. The remaining storage impacts presented in Table 9-3 (Host Customer) and Table 9-4 (Societal) should be included in BCA tests to the extent they are relevant to the jurisdiction's applicable policy goals (see Chapter 3).

Table 9-1. Potential Impacts of Distributed Storage: Electric Utility System

Type	Utility System Impact	Benefit or Cost	Notes, or Typical Applicability
Generation	Energy Generation	🔴	A cost because storage technologies generally require more energy to charge than what they discharge
	Generation Capacity	🟠	A benefit, depending upon the storage use case and the electric utility's ability to affect the operation of the storage device; otherwise, a cost if storage device charges during peak periods
	Environmental Compliance	🟠	A benefit or cost depending upon system environmental profile during charging and discharging times
	RPS/CES Compliance	🔴	A cost because storage technologies generally require more energy to charge than what they discharge
	Market Price Response	🟠	A benefit or cost depending upon market conditions during charging and discharging times
	Ancillary Services	🟠	A benefit or cost depending upon the storage use case and the electric utility's ability to affect the operation of the storage device
Transmission	Transmission Capacity	🟠	Potentially benefits depending upon the storage use case and the electric utility's ability to affect the operation of the storage device; otherwise, potentially costs if storage device charges during transmission peak periods
	Transmission Line Losses	🟠	
Distribution	Distribution Capacity	🟠	Potentially benefits depending upon the storage use case and the electric utility's ability to affect the operation of the storage device; otherwise, potentially costs if storage device charges during distribution peak periods
	Distribution Line Losses	🟠	
	Distribution O&M	🟠	
	Distribution Voltage	🟠	
General	Financial Incentives	🔴	Typically costs to the extent they are relevant
	Program Administration Costs	🔴	
	Utility Performance Incentives	🔴	
	Credit and Collection Costs	🟢	A benefit because customer savings make bill payment easier, especially for low-income customers
	Risk	🟢	Potentially benefits depending upon the storage use case and the electric utility's ability to affect the operation of the storage technology during peak or emergency periods
	Reliability	🟢	
	Resilience	🟢	

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

Table 9-2 presents the potential impacts of distributed storage on gas utility or other fuel systems. It illustrates that (a) there are no distributed storage resources for natural gas utilities, and (b) electric utility storage resources do not affect other fuels.[37]

[37] This table is included for consistency with the other tables in Part III.

Table 9-2. Potential Impacts of Distributed Storage: Gas Utility or Other Fuel System

Type	Non-Electric Energy System Impact	Gas Utility Storage Resources	Electric Utility Storage Resources that Affect Other Fuels
Other Fuel: Energy	Fuel and Variable O&M	Not applicable. There are no distributed storage resources for natural gas utilities.	Not applicable. Electric utility storage resources do not affect other fuels.
	Capacity		
	Environmental Compliance		
	Market Price Response		
Other Fuel: General	Financial Incentives (e.g., rebates)		
	Program Administration Costs		
	Utility Performance Incentives		
	Credit and Collection Costs		
	Risk		
	Reliability		
	Resilience		

Table 9-3 presents the potential host customer impacts of distributed storage (see Section 4.4).

Table 9-3. Potential Impacts of Distributed Storage: Host Customer

Type	Host Customer Impact	Benefit or Cost	Notes, or Applicability
Host Customer	Host portion of DER costs	● (red)	Costs to the extent they exist
	Interconnection Fees	● (red)	
	Risk	● (green)	Benefits depending upon the storage use case and the extent the host customer controls the device
	Reliability	● (green)	
	Resilience	● (green)	
	Tax Incentives	● (green)	Potentially a benefit for those resources where they apply
	Host Customer NEIs	● (orange)	A benefit or cost depending on the NEI (see Section 9.4.4)
	Low-Income NEIs	● (green)	A benefit for low-income storage only

● = typically a benefit for this resource type; ● = typically a cost for this resource type; ● = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

Table 9-4 presents the potential societal impacts of distributed storage.

Table 9-4. Potential Impacts of Distributed Storage: Societal

Type	Societal Impact	Benefit or Cost	Notes, or Applicability
Societal	Resilience	● (green)	Potentially a benefit depending upon the storage use case and the extent to which critical customers control the device
	GHG Emissions	● (orange)	Benefits or costs depending upon system environmental profile during charging and discharging times
	Other Environmental	● (orange)	
	Economic and Jobs	● (orange)	Potentially a net benefit or net cost depending on use case and net utility system benefits
	Public Health	● (orange)	Same as GHG Emissions and Other Environmental
	Low Income: Society	● (green)	Typically a benefit depending on siting and low-income participation
	Energy Security	● (orange)	Potentially a benefit or cost depending on use case and net utility system benefits

● (green) = typically a benefit for this resource type; ● (red) = typically a cost for this resource type; ● (orange) = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

9.4 Key Factors that Affect Distributed Storage Impacts

Determining a distributed storage resource's cost-effectiveness depends upon a clear identification of the use case(s) it intends to target. Although some impacts from distributed storage are clearly a benefit or cost, there are numerous impacts where the net effect varies from project to project. Table 9-5 provides an example of analyzing potential benefits of energy storage based on a BCA of a range of possible use cases.

Table 9-5. Cost-Effectiveness Analysis of Storage Use Cases

Use Case		Estimated Share of 1766 MW Recommendation		Millions $		Benefit/Cost Ratio
		%	MW	Combined Benefits (Market Revenue + System Benefits)	Cost	
Investor-Owned Utility Grid Mod Asset: Distributed Storage at Utility Substations		40%	707	1301	387	3.36
Municipal Light Plant Asset		10%	177	446	97	4.60
Load Serving Entity/Competitive Electricity Supplier Portfolio Optimization		8%	141	158	77	2.05
Behind the Meter	C&I Solar + Storage	6%	106	103	58	1.78
	Residential Storage	4%	71	19	53	0.49
	Residential Storage Dispatched by Utility	5.5%	96	129	39	2.43
Merchant	Alternative Technology Regulation Resource	1.5%	28	45	15	3.00
	Storage + Solar	10.5%	185	373	102	3.66
	Stand-alone Storage or Co-Located with Traditional Generation Plant	9.5%	168	405	92	4.40
Resilience/Microgrid		5%	87	133	48	2.77

Source: State of Massachusetts 2017.

The box below provides three illustrative examples of how the relevant impacts for a distributed storage resource might vary between different use cases.

Illustrative Distributed Storage Use Case Tradeoffs

Example 1: The storage resource seeks to provide multiple host customer benefits in the form of reliability, resilience, and bill management. For all three of these benefits, the storage resource must maintain a certain state of charge (i.e. how full the storage resource is) to be able to provide the services when needed. If, however, there is a forecasted system reliability or resilience event that requires the storage resource to remain fully charged, then the resource would not be capable of simultaneously discharging to manage the customer's bill.

Example 2: The storage resource seeks to provide both system generation and distribution capacity, but there will need to be a clear understanding of relative priority of these services for instances when the resource cannot provide both in full. For example, if the distribution capacity need is from 12:00–4:00 PM while the generation capacity need is from 4:00–8:00 PM, a storage resource with four hours of duration would not be able to fully meet both obligations (It would have insufficient time to recharge the resource between providing each service). A BCA will need to contemplate what mechanisms exist to determine which service the storage resource prioritizes in the event of a conflicting obligation.

Example 3: The storage resource seeks to provide system frequency regulation (an ancillary service) to the bulk power system and distribution deferral. Since frequency regulation requires a resource to be able to either inject or withdraw, the ability for the storage resource to provide both services depends on the timing and direction of the needed responses. For example, if there is a temporal overlap of the needs (e.g., 4:00–6:00 PM) and the frequency regulation dispatch requires the storage resource to charge while the distribution deferral dispatch requires the storage resource to discharge, then the storage resource will not be able to simultaneously provide both services using the same capacity.

9.4.1 Technology Characteristics

The specific technical characteristics (largely based on the type and chemistry) of a distributed storage resource may affect its ability to provide certain services. For example, some distributed storage assets may have durations (the amount of time the asset can sustain a continuous charge or discharge at a fixed level) that are less than the minimum requirement to provide a service such as generation capacity through the organized wholesale market.[38] In addition, the specific technology may affect other eligibility requirements the distributed storage resource must meet to provide certain services, such as being synchronized to the electricity system. As a result, any BCA should consider how the technical characteristics of a distributed storage resource affect which impacts are relevant, including the relative scale of each.

9.4.2 Technology Operating Profile

Distributed storage can operate in several different modes, including electricity withdrawal (i.e., consumption), electricity injection, and load modulation. Understanding distributed storage impacts requires an understanding of when the distributed storage asset plans to operate in each mode, as well as an articulation of the specific benefits and costs attributable to each mode. For example, a distributed storage resource would likely exhibit load-shifting behavior in order to provide a service like distribution

[38] To meet minimum run-time requirements, however, a distributed storage resource could lower its discharge amount (kW) to increase its effective duration.

capacity but might instead operate to modulate load (i.e., real-time fluctuations) when providing ancillary services that require a more dynamic response.

While these operational modes allow distributed storage to provide additional value in the form of flexibility, they will also affect the useful lifetime of the resource. For example, as the number of cycles (switching from charging to discharging) and depth of discharge (the ratio of how much the storage resource is charged and discharged relative to its full capability) increase, the expected lifetime of the storage asset will decrease. Consequently, a BCA for distributed storage should consider the expected useful lifetime of the resource as that will affect how far into the future the BCA should account for relevant impacts.

Understanding distributed storage impacts requires an understanding of when the distributed storage asset plans to operate in each mode, as well as an articulation of the specific benefits and costs attributable to each mode.

In addition, a BCA should consider the fact that distributed storage resources have duration limitations, since they cannot indefinitely charge or discharge. These resources also have less than 100 percent roundtrip efficiency, as some energy is lost between the resource charging and discharging. These characteristics make it imperative to understand both how and when the distributed storage resource will operate because the benefits provided and costs incurred during the times of operation will affect the cost-effectiveness of the resource. For example, if the value for discharge is sufficiently higher than the cost incurred to charge, then there may be sufficient energy arbitrage opportunity despite losing energy in the process. This example highlights the importance of understanding the time-varying nature of the distributed storage resource's operation and associated benefits and costs. These benefits and costs are very dependent on the host customer's rate structure.

9.4.3 Other Fuel Impacts

Distributed storage—in isolation from other DER types—will not have any impacts on natural gas or other fuels because (a) there are currently no distributed storage resources for natural gas utilities, and (b) electric utility storage resources do not affect other fuels.

Distributed storage resources might have impacts on natural gas or other fuels when combined with electrification DERs. In these cases, storage could help alleviate electric system spikes, potentially paving the way for more economic electrification. Any such impacts on natural gas supplies and emissions should be evaluated on a case-by-case basis.

9.4.4 Host Customer Non-Energy Impacts

Table 9-6 presents a summary of host customer NEIs that distributed storage resources might potentially create. These impacts can sometimes be in the form of benefits and sometimes costs. The presence, direction, and magnitude of distributed storage NEIs will depend upon many factors, including the use case for the storage, the type of host customer (low-income, residential, commercial, industrial), the host customer's needs, and the rate design in place.

Table 9-6 indicates whether the category of NEIs is typically a cost, a benefit, or either in most common applications. The actual direction of the impact, however, may vary and should be determined on a case-by-case basis.

Table 9-6. Potential Host Customer Non-Energy Impacts of Distributed Storage

Category	Benefit or Cost	Examples
Transaction costs	● (cost)	− Researching technologies, application fees and processes
Asset value	● (benefit)	− Increased building value
Productivity	● (either)	− Productivity gains from consistent power source − Loss of productivity due to non-host customer obligation*
Economic well-being	● (either)	− Stable operating costs − Resource may add to customer debt profile
Comfort	● (either)	− Thermal comfort may be positively or negatively impacted − Noise pollution from distributed storage resource
Health & safety	● (either)	− Safety concerns associated with operation of storage device − Provide electricity to critical health devices during outage
Empowerment & Control	● (either)	− Psychological benefit in the form of personal empowerment − Energy independence − Inconvenience of non-host customer obligations
Satisfaction/Pride	● (either)	− Contribution to addressing environmental concerns

● = typically a benefit for this resource type; ● = typically a cost for this resource type; ● = either a benefit or cost for this resource type, depending upon the application of the resource.

9.4.5 Air Emissions Impacts

Distributed storage resources can either reduce or increase air emissions, depending upon the use case for the storage device, the marginal emission rates during charging times, the marginal emission rates during the discharging time, and the round-trip efficiency of the storage resource.

As discussed in Chapter 5, air emission impacts should account for two important factors: (a) the time period for which the DER operates; and (b) the marginal emission rates of the utility system at the time when the DER operates. Distributed storage devices can potentially have significant intra- and inter-day variation, making it especially important to account for the detailed time periods that they are expected to operate.

The *Ensure Symmetry* principle requires accounting for both reduced and increased air emissions from EE resources, to the extent that they occur.

9.4.6 Interconnection Location and Process

The cost- effectiveness of a distributed storage resource fundamentally depends on its interconnection parameters, both in terms of resource location and the process for gaining utility approval to be built.

Interconnection location

Like other DERs, where distributed storage is interconnected will affect its cost-effectiveness. First, the set of relevant impacts for a distributed storage resource depends on whether the resource is interconnected in front of or behind the customer's meter. For example, if a distributed storage resource is interconnected in front of the customer's meter, then it is incapable of providing the host customer with reliability or resilience benefits. (See Section 5.5.)

Second, and related to the first, the distributed storage resource may be eligible for certain financial incentives (e.g., the federal Investment Tax Credit, or ITC) if it is co-located with solar PV and a certain amount of the storage resource's charging is supplied by the solar PV system.

Finally, a distributed storage resource's benefits will depend on where utility system needs are in relation to the resource's interconnection location. For example, if a distributed storage resource is in an area where there are no distribution capacity needs, then even if the resource has the technical capability to provide that service, it should not be credited with that benefit. (See Section 5.3.)

Interconnection process

There are three key aspects of the interconnection process that could affect a distributed storage resource's cost-effectiveness:

- Assumptions regarding the storage resource's intended operation could impact interconnection costs and hosting capacity limits.
- Assumptions regarding the storage resource's ability to inject energy onto the grid, which could impact its ability to provide certain ancillary services that require injections of energy rather than withdrawal.
- Assumptions regarding how the interconnection process allows distributed storage to utilize unused interconnection rights of an existing resource (e.g., solar PV, assuming all engineering concerns are met), which could lead to lower costs by virtue of a more streamlined interconnection process. For example, if an existing solar PV system has 5 MW of injection rights from the utility, a co-located storage resource could install a control system that ensures the total aggregate injection of the storage and solar PV resources never exceeds 5 MW.

9.4.7 Compensation Mechanisms

There are two key factors affecting distributed storage compensation mechanisms: market rules and rate design.

Market rules

Market rules—which can broadly be applied to both organized wholesale markets and any utility programs or procurements—determine how distributed storage resources capture value for responding to price and dispatch signals to deliver system benefits. For wholesale markets, FERC Order 841 (FERC 2018) requires all ISOs and RTOs to develop energy storage participation models allowing this resource type (including FOM and BTM storage) to provide and be compensated for all wholesale market services they are technically capable of providing. This order creates additional opportunities for distributed storage to capture wholesale market value.

Separately, utility programs and procurements can provide distributed storage resources with compensation to deliver local value. An important consideration for these types of programs and procurements is whether they allow the distributed storage resource to seek alternative sources of revenue when not being utilized by the utility.

Rate design

When located behind the customer's meter (i.e., co-located with load), the applicable retail rate will likely affect the storage device's use case, which will affect its benefits and costs. For example, time-varying rate structures and demand charges provide price signals that could encourage charging when rates are lower and discharging when rates are higher, or by reducing the customer's peak demand.

As more jurisdictions adopt sophisticated rate structures, it will become increasingly important to assess how those rate structures inform a storage resource's operational profile, and consequently its impact on cost recovery for the utility. For example, if a jurisdiction has a TOU rate that charges higher prices for electricity consumption during peak hours, there may be a growing number of storage resources operated to minimize bill impacts from on-peak rates. If rates do not accurately reflect costs on the system, the use of storage for TOU rate arbitrage could have negative impacts on system costs and electricity rates.

In general, utilities may have greater levels of confidence from a planning and operations perspective if they directly own and control a resource.

9.4.8 Resource Ownership and Control

The entity that owns and controls distributed storage may affect the resource's cost-effectiveness. In some cases the entity owning the storage might be different from the entity controlling it.

In terms of ownership, the primary effect on cost-effectiveness will be the allocation of various benefits or costs. For example, while a utility-owned distributed storage resource may entail the utility bearing all integration costs and accruing all benefits, a customer-owned distributed storage resource may involve some level of benefit and cost sharing.

Distributed storage control may also affect which impacts are relevant for the resource. In general, utilities may have greater levels of confidence from a planning and operations perspective if they directly own and control a resource. In these instances, the utility will have a clear line of sight into which services it seeks the distributed storage resource to provide and can control it accordingly. However, if control resides with the customer or another third party, the utility must rely on market-based mechanisms (e.g., dynamic pricing; competitive procurements; etc.) to elicit the desired response from the distributed storage resource.

This dynamic informs cost-effectiveness in two key regards. First, the level of control the utility requires on the distributed storage resource will affect the overall cost because more advanced control technologies may be more expensive. Second, if the utility does not directly control the distributed storage resource, it may assign the resource a decremented value to "compensate" for the reduced level of utility confidence that the resource will deliver the targeted service(s), which could lead to unnecessary investments in additional resources as a result.

9.5 Common Challenges for Determining Storage Benefits and Costs

9.5.1 Determining the Operating Profile

As described earlier, as part of a BCA it is critical to determine how and when a distributed storage resource intends to operate because the temporal nature of its operation will materially affect its benefits and costs. While it is generally easier to predict the effect on net loading from DERs such as solar PV and EE, determining this effect for distributed storage is more complex given its potentially dynamic operation. For example, the multiple potential operational modes for distributed storage adds complexity to determining when the resource will operate in each. Further, while the resource may plan to provide a certain set of services at the time of its interconnection, it may seek to adjust its operations in the future to target other services as a result of changing market dynamics or policies.[39]

If the utility directly owns and operates the distributed storage resource, or if it has an executed contract with the third-party distributed storage owner to provide certain services, it will likely have greater confidence over the resource's planned operational profile. This confidence will allow it to more conclusively determine the net benefit or cost of each relevant impact.

Alternatively, if the storage resource is owned and operated by a non-utility party, the utility may seek to collect certain information—including as part of the interconnection process—that will enable it to more effectively determine the resource's planned operational profile. In the case of non-utility ownership and operation, jurisdictions should continue to identify best practices for the types of information needed to determine how the storage resource will likely operate in the future based on proposed operational characteristics.

9.5.2 Determining the Counterfactual Host Customer Baseline

If distributed storage is used to modify load as if it were a DR resource, there will be challenges akin to those discussed in Section 7.5.2 for how to determine the counterfactual baseline to measure the quantity of DR provided. Determining a storage resource's performance as a DR resource requires an assessment of what the customer's energy consumption would have been absent the storage resource.

To the extent a distributed storage resource is coupled with load (i.e., behind the same meter), it is critical to discern what impact the storage resource's operation has on the customer's load and how much of this impact is due to an intentional action to meet the dispatch instructions for the storage resource.

Determining the counterfactual baseline will require an understanding of the storage resource's typical operational profile, similar to how baselines are used to determine a customer's typical consumption profile. Alternatively, if the storage resource has its own production meter separate from the customer's load meter, then the storage resource's operation can effectively be separated from customer load, allowing for a more direct analysis of changes in the customer's net load due to dispatch instructions.

9.5.3 Accounting for Provision of Multiple Services

While all DERs can stack multiple values (see Section 5.3), distributed storage offers unique considerations: Its dispatchability allows for targeted application to various services, but its duration limitations warrant consideration about potential tradeoffs in services it can provide. Evaluating a distributed storage resource requires attention to which services it will likely provide and how it will balance potential conflicts that prevent the resource from fully meeting all of its intended use cases (e.g., operation during one part of the day rendering the resource unavailable for another service later that day).

> Evaluating a distributed storage resource requires attention to which services it will likely provide and how it will balance potential conflicts that prevent the resource from fully meeting all of its intended use cases.

This is an emerging focus area in the industry, but further work is needed to more formally define a framework that stipulates rules governing

[39] If the distributed storage resource changes its originally intended operating profile but does not seek to increase the amount of power it can inject onto the system, it may not require a new interconnection review.

distributed storage resource's ability to provide multiple services. The California Public Utilities Commission (CPUC) and New York Public Service Commission (NY PSC) have focused on whether the storage resource is providing reliability-based services and whether services can be differentiated in terms of timing or the storage resource's capacity dedicated to meet each service (CPUC 2018; NYPSC 2018). Ultimately, while there may be standardized aspects of a framework guiding the ability of distributed storage resources to stack multiple services, there may need to be variation across jurisdictions given the unique market, policy, and regulatory environment of each.

9.6 Lost Revenues and Rate Impacts

Lost revenues and potential rate impacts should not be included in cost-effectiveness analyses. Instead, DER lost revenues and rate impacts should be analyzed separately using rate, bill, and participation analyses. (See Section 2.3 and Appendix A.) In conducting BCAs, therefore, lost revenues should be identified so that they can be properly excluded from BCAs and properly included in rate, bill, and participation analyses.

In general, several key factors affect the extent to which DERs might create rate impacts:

- *Increases in utility system costs* will put upward pressure on rates.
- *Reductions in utility system costs* will put downward pressure on rates.
- *Reductions in sales* from DER resources will put upward pressure on rates.
- *Increases in sales* from DER resources will put downward pressure on rates.
- *Rate design* will affect the amount of lost or increased revenues created by the DER.

Distributed storage resources will typically increase utility system costs because of financial incentives or program administration costs, but will reduce utility system costs by avoiding generation, transmission, and distribution costs (see Table 9-1).

Distributed storage resources will typically create lost revenues by (a) allowing host customers to reduce their energy bill by reducing their energy consumption, especially during high-price hours; and (b) allowing host customers to reduce their energy bill by reducing demand charge payments, where such charges are in place. The lost revenues from distributed storage resources will depend upon many factors, including the storage device's use case and the rate design in place.

Regulators and other stakeholders that are concerned about distributed storage rate impacts could consider the following: (a) conduct a long-term rate, bill, and participation impact analysis, (b) seek and implement rate designs and storage initiatives likely to mitigate equity concerns, (c) seek ways to expand customer participation, especially among low- and moderate-income customers, and (d) periodically review impacts as distributed storage deployment rates increase.

10. ELECTRIFICATION

This chapter describes the benefits and costs most relevant to electrification resources. It identifies key factors that affect electrification benefits and costs and provides guidance on addressing common challenges with electrification cost-effectiveness analyses.

10.1 Summary of Key Points

- Electrification resources can include technologies to replace other fuels in buildings, as well as technologies to replace other fuels in the transportation sector, such as EVs.
- Electrification resources will increase net electric utility system costs because they require increased electricity generation. However, they will also reduce costs associated with the other fuels that they replace. Consequently, electrification resources are likely to be cost-effective only when the benefits of other fuels are included in a jurisdiction's cost-effectiveness analyses.
- The amount of added costs to the electric grid due to electrification will depend upon when the technologies are utilized, which in turn will be influenced by the host customer rate structure. This is particularly true for electrification measures whose demands can be most flexibly managed by customers, such as EVs.
- The added costs to the electric grid due to most electrification technologies may also be reduced when combined with DR, such as "managed charging" of EVs and direct load control of heat pumps.
- EVs with V2G capability can further mitigate increased costs to the grid as a result of electrification, and potentially even reduce net *electric utility* system costs, because of their ability to function as storage.
- Electrification measures can reduce net air emission impacts (both GHG and other pollutants), as long as the marginal emissions from the electricity grid are low enough relative to the marginal emissions of the displaced fuel.
- Different charging levels for EVs—particularly the prevalence and use of fast charging with short duration draws of large amounts of power—can potentially impact T&D capacity needs and costs.
- Electrification resources will typically create increased revenues for the electric utility. These might lead to reduced electricity rates, depending upon the magnitude of increased revenues, utility system costs, and utility system benefits. Rate impacts from electrification resources are more appropriately assessed using rate, bill, and participation analyses (Appendix A).
- Electrification resources will sometimes create lost revenues for the gas utility. These might lead to increased rates, depending upon the magnitude of lost revenues and the magnitude of gas utility system benefits.

10.2 Introduction

For the purposes of this manual, electrification is defined as the conversion of energy use from a non-electric fuel source to electricity. This includes:

- Electrification of buildings and industry (for any of a wide range of potential end-uses, including space heating, water heating, and industrial processes).
- Transportation electrification (e.g., light-, medium- and heavy-duty EVs; electric flight and electric marine applications).

Electrification can be "partial" (e.g., a plug-in hybrid electric vehicle (PHEV) or a heat pump retrofit in a home where the existing fossil fuel furnace or boiler remains as a secondary system) or "complete" (e.g., a battery electric vehicle (BEV) or a home switching entirely to electric heat).

The fundamental BCA principles described in Chapter 2 can be used to identify the relevant benefits and costs for electrification, as with all DER types. In many cases, identifying whether a particular benefit or cost is relevant to electrification requires defining the specific electrification technology and use case.

10.3 Benefits and Costs of Electrification

The tables in this section summarize the full range of potential benefits and costs of electrification resources (see Chapter 4 for definitions of impacts). Each impact is described as a benefit, a cost, or either, depending on the most common applications of this technology. There might be some less-common applications where a cost could be a benefit, or vice versa. The tables include notes on applicability that provide further explanation for those impacts that may be either a cost or benefit.

Table 10-1 presents the potential benefits and costs of electrification on the electric utility system, while Table 10-2 presents the impacts of electrification on the gas utility system. All electrification utility system impacts presented in these tables should be included in BCA tests. The remaining electrification impacts presented in Table 10-3 (Host Customer) and Table 10-4 (Societal) should be included in BCA tests to the extent they are applicable to the jurisdiction's policy goals (see Chapter 3).

Table 8-1 shows that many electrification measures have the potential to function as DR resources. In addition, EVs with V2G capability can function as storage resources (see Chapter 9). The characterization of impacts in Table 10-1 as benefits or costs addresses only the electrification features of these technologies because (a) not all electrification measures can provide DR and/or storage functionality; (b) for any DR or storage functionality to have impact it must be activated through a utility system initiative; and (c) not all EVs, heat pumps, electric water heaters and/or other electrification technologies with DR and/or storage capability that are installed as a result of a utility system electrification program will get enrolled in complementary DR and/or storage initiatives. The impacts of DR and storage are addressed in Chapters 7 and 9, respectively. The impacts of multiple DERs—which would encompass the combination of electrification and DR, for example—are discussed in Part IV of this manual.

Table 10-1. Potential Impacts of Electrification: Electric Utility System

Type	Utility System Impact	Benefit or Cost	Notes, or Typical Applicability
General	Energy Generation	●	A cost because electrification increases electricity generation. Cost for many measures can be reduced through economic dispatch using DR and further reduced through use of storage capabilities of V2G EVs. (See Chapters 7 and 9.)
	Generation Capacity	●	A cost because most uncontrolled electrification measures will add some demand on system peak (electric heat in summer peaking system is a possible exception). Resulting capacity cost for many measures can be reduced through DR; it can be eliminated or even made negative (i.e., a grid benefit) if storage capability of V2G EVs is utilized. (See Chapters 7 and 9.)
	Environmental Compliance	●	By adding load to the grid, electrification can increase electric costs of compliance (but reduce other fuel costs of compliance).
	RPS/CES Compliance	●	By increasing electricity load, the quantity of renewables needed to meet RPS increases.
	Market Price Response	●	Any increase in electricity consumption will increase market clearing prices where there are competitive wholesale markets.
	Ancillary Services	●	By itself, electrification could increase ancillary services costs. However, both EVs and water heaters offer the ability to provide ancillary services when enabled through DR; if that capability is utilized, this can become a benefit. (See Chapter 7.)
Transmission	Transmission Capacity	●	Most uncontrolled electrification measures will add some demand at transmission peak time (electric heat in summer peaking region a possible exception). Resulting capacity cost for many measures can be reduced through DR and eliminated or even made negative (i.e. a grid benefit) if storage capability of V2G EVs is utilized. (See Chapters 7 and 9.)
	Transmission System Losses	●	Any consumption increase will increase losses.
Distribution	Distribution Capacity	●	Most uncontrolled electrification measures will add some demand at distribution peak time (electric heat in summer peaking area is a possible exception). Resulting capacity cost for many measures can be reduced through DR and eliminated or even made negative (i.e. a grid benefit) if storage capability of V2G EVs is utilized. (See Chapters 7 and 9.)
	Distribution System Losses	●	Any consumption increase will increase losses.
	Distribution O&M	●	Any consumption increase will increase O&M.
	Distribution Voltage	●	Added loads will make distribution voltage more challenging to keep at desired levels.

Type	Utility System Impact	Benefit or Cost	Notes, or Typical Applicability
General	Financial Incentives	●	Costs, where relevant
	Program Administration Costs	●	
	Utility Performance Incentives	●	
	Credit and Collection Costs	●	A benefit because other fuel savings may make it easier for customers with electrified end-uses to afford electricity bills.
	Risk	●	Adds risk to electric grid but may be offset by reduced risk associated with displaced fuel(s)
	Reliability	●	By adding load to the grid, electrification will decrease electric system reliability. For many measures that effect can be reduced through DR; it can be eliminated or made negative (i.e., a grid benefit) if storage capability of V2G EVs is utilized. (See Chapters 7 and 9.)
	Resilience	○	Electrified building end-uses do not affect electric system resilience; EVs functioning in V2G mode, could improve resilience by functioning as storage. (See Chapter 9.)

● = typically a benefit for this resource type; ● = typically a cost for this resource type; ● = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

Table 10-2 presents the potential benefits and costs of electrification on gas utilities and other fuel systems. By definition, electrification programs decrease the use of other fuels.

Table 10-2. Potential Impacts of Electrification: Gas Utility and Other Fuel System Impacts

Type	Non-Electric Energy System Impact	Benefit or Cost	Notes/Typical Applicability
Other Fuel: Energy	Fuel and Variable O&M	🟢	Any decrease in demand for other fuels caused by electrification will produce other fuel cost reductions.
	Capacity	🟢	To the extent electrification causes a decrease in peak demand for other fuels, it can avoid capital investment in system capacity. Electrification of new construction also eliminates capital cost associated with connection to other fuel delivery systems.
	Environmental Compliance	🟢	By reducing consumption of other fuels, electrification may reduce cost of compliance with environmental regulations for those other fuels (depending on how the regulations are structured).
	Market Price Response	🟢	Any decrease in consumption of other fuels as a result of electrification will lower market clearing prices where there are competitive wholesale markets.
Other Fuel: General	Financial Incentives (e.g., rebates)	🔴	A cost to other fuel systems only if applicable to those systems (e.g. for natural gas non-pipe solutions)
	Program Administration Costs	🔴	
	Utility Performance Incentives	🔴	
	Credit and Collection Costs	🟢	If total energy bills across all fuels decline, customers may be better able to pay all bills.
	Risk	🟢	Lower consumption resulting from electrification should reduce risk (e.g. of exposure to future fuel price volatility).
	Reliability	🟢	Lower consumption of displaced fuel should increase reliability of supply of that fuel.
	Resilience	🟢	Reduced reliance on displaced fuels should reduce the amount of infrastructure for delivery of that fuel that needs to be replaced as a result of storms or other catastrophes.

🟢 *= typically a benefit for this resource type;* 🔴 *= typically a cost for this resource type;* 🟠 *= either a benefit or cost for this resource type, depending upon the application of the resource;* ○ *= not relevant for this resource type.*

Table 10-3 presents the potential host customer impacts of electrification.

Table 10-3. Potential Impacts of Electrification: Host Customer

Type	Host Customer Impact	Benefit or Cost	Notes/Typical Applicability
Customer	Host Customer Portion of DER Costs	🔴	Both the cost of the electric products (e.g., EVs or heat pumps) and possible costs to upgrade electric service necessary to use them (including EV charging equipment and related electrical upgrades)
	Interconnection Fees	○	Potentially a cost for V2G, otherwise not applicable
	Risk	🟠	Potentially a cost due to reduced electricity fuel diversity; potentially a benefit due to reduced volatility of other fuel prices
	Reliability	🟠	EVs can function in times of gasoline shortages and heat pumps can keep buildings heated if there are problems with fossil fuel access or with fossil fuel heating systems; conversely, there can be reliability issues tied to power outages.
	Resilience	🟢	V2G storage capability can be a benefit to host customers if used as back-up power during grid outages; otherwise not applicable.
	Tax Incentives	🟢	Potentially a benefit where relevant.
	Host Customer NEIs	🟠	Benefit or cost depending on NEI (see Section 10.4.5)
	Low-income NEIs	🟢	For low-income electrification only

🟢 *= typically a benefit for this resource type;* 🔴 *= typically a cost for this resource type;* 🟠 *= either a benefit or cost for this resource type, depending upon the application of the resource;* ○ *= not relevant for this resource type.*

Table 10-4 presents the potential societal impacts of electrification.

Table 10-4. Potential Impacts of Electrification: Societal

Type	Societal Impact	Benefit or Cost	Notes/Typical Applicability
Societal	Resilience	🟠	Depends upon whether reduced gas consumption affects critical customers and whether increased electricity consumption stresses the grid
	GHG Emissions	🟠	Depends on use case and hourly environmental profile of electricity grid relative to fossil fuel combustion emissions displaced by appliance/vehicle
	Other Environmental	🟠	
	Economic and Jobs	🟠	Potentially a net benefit or net cost depending upon fuels displace
	Public Health	🟠	Same as GHG emissions and other environmental
	Low Income: Society	🟢	Potentially a benefit depending on siting and low-income participation
	Energy Security	🟢	Potentially a benefit depending upon the extent that petroleum products are being displaced

🟢 *= typically a benefit for this resource type;* 🔴 *= typically a cost for this resource type;* 🟠 *= either a benefit or cost for this resource type, depending upon the application of the resource;* ○ *= not relevant for this resource type.*

10.4 Key Factors that Affect Electrification Impacts

10.4.1 Technology Characteristics

Electrification can be applied to a variety of end-uses, including EVs; electric heating, water heating, cooling, cooking, drying and other end-uses in homes and business; and electric processes for industrial customers. There are also a number of different technology options for each of those end-uses. Put simply, not all EVs or heat pumps or electric water heaters or electric cooktops are the same. The different characteristics of those technologies can affect the cost-effectiveness of electrification in a variety of ways.

First, the efficiency of an electrification technology can have important implications for its cost-effectiveness. The more efficient the electrification measure, the lower the added costs to the electric system for the same amount of displaced fossil fuel. For example, a heat pump can be two to four times more efficient at providing electric heat than electric resistance heating systems. Thus, electrifying space heating with a heat pump may add 50 percent to 75 percent less cost to the grid than electrification with electric resistance heat. Of course, if there is an added cost associated with greater electric efficiency—as is the case with heat pumps, which are much more expensive than electric resistance heat.

The change in Source Energy consumption resulting from an electrification measure is equal to the total amount of energy required to produce (in a power plant) and deliver (across power lines) the electricity consumed by an electrification measure, minus the gasoline, natural gas, fuel oil, propane or other fuels displaced by the measure.

Specifically, 1 kWh of electricity has 3,412 BTUs of energy, while a fossil fuel fired power plant can burn 7,000 (roughly 50% efficient) to 11,000 BTUs (roughly 30% efficient) or more of fuel to produce one kWh. The amount of fuel burned to produce a kWh is called the power plant's "heat rate." In 2018, the average heat rate for gas-fired power plants was 7,822 BTUs/kWh, or an average efficiency of about 44% (EIA 2019a). There are also losses associated with delivering a kWh of electricity from power plants to homes and businesses, averaging about 5% in the United States (EIA 2019b).

Many electrification measures (e.g., high performance heat pumps) can be considered "energy efficiency" measures because they reduce total source energy consumption.[40] On the other hand, some potential electrification measures (e.g., electric resistance heating systems) can increase source energy consumption.[41] It is in fact possible for some electrification measures that increase source energy consumption to be cost-effective, while some that reduce source energy consumption may not be cost-effective. As such, in cases where a jurisdiction adopts policies that preclude promotion of electrification measures unless they reduce total energy consumption (whether source energy or site energy

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[40] For example, on an electric grid with an average marginal heat rate of 8,000 Btu/kWh and 8 percent average line losses, a high-performance heat pump with an average coefficient of performance (COP) of 3.0 would consume 24 percent less *source energy* per unit of heat produced than a 90 percent efficient propane furnace. COP is the ratio of energy output (in the form of heat in this example) to energy input (electricity in this example).

[41] For example, on an electric grid with an average marginal heat rate of 8000 Btu/kWh and 8 percent average line losses, electric resistance heating, which has a coefficient of performance (COP) of 1.0, would consume more than twice as much *source energy* per unit of heat produced than a 90 percent efficient propane furnace.

consumption)[42] any such constraints are policy choices and not necessarily reflections of cost-effectiveness.

Second, many electrification measures have the potential to be managed by customers to minimize costs to the grid (especially if they see hourly price signals) and/or to be controlled directly through DR programs. Some electrification measures—namely EVs and electric water heaters—are particularly well-suited to load management through DR programs.

Unlike other electrification measures, EVs with V2G capability offer the potential to actually reduce net system peak demands and/or net T&D peak demands.

Third, while many EVs allow only one-way electricity flows (from the grid to the vehicle for charging), some have two-way flow capability (also allowing vehicle-to-grid flows). EVs with that unique feature can function as storage resources for the grid (similar to other storage options discussed in Chapter 9). This allows not only charging during times of low prices and/or low net demand, but also the ability to push electricity back onto the grid during times of high prices and/or high net demand. Thus, unlike other electrification measures, EVs with V2G capability offer the potential to actually *reduce* net system peak demands and/or net T&D peak demands.

EVs with V2G capability even have the potential to reduce total electric generation (energy) costs—if costs avoided when they put power onto the grid are high enough to offset the costs of increased consumption when they are taking power off the grid.[43] Of course, the extent to which V2G storage capabilities will actually affect system peak demands and/or energy costs will depend on the extent to which the vehicle owners both participate in utility system initiatives to utilize the storage capabilities and have their vehicles plugged in and accessible to the grid at the times their storage capabilities may be needed.

Finally, different types and even different models of electrification technology can have significant impacts on host customer non-energy impacts. For example, advanced air source heat pumps can improve comfort relative to fossil fuel heating systems, while less advanced systems can create comfort problems, particularly in colder climates. Similarly, electric induction cooktops can enhance cooking performance relative to gas or propane cooktops, while standard electric coil cooktops offer less heat control than gas or propane (though all electric cooktops provide health and safety benefits relative to gas or propane). Both high performance heat pumps and induction cooktops typically cost more than standard electric alternatives. Thus, in jurisdictions whose policies dictate that host customer impacts be included in cost-effectiveness assessments, it will be important to be clear about which electric technology is being assessed and to characterize the specific attributes of each technology.

[42] The concept of "source efficiency" can be important when the marginal generation on the grid is fossil fuel-powered. In such cases, there are tradeoffs—affecting both cost and environmental emissions—between increased fossil fuel consumption on the grid and reductions in direct fossil fuel consumption by consumers in their vehicles, homes, and businesses. Source efficiency loses relevance to the extent that renewable energy sources such as wind and solar—whose "fuel" has no cost and which produce no emissions—are the marginal generation resource on the grid.

[43] Consider the following hypothetical example in which total electricity used for driving an EV was 3000 kWh per year, where the EV storage functionality was used to put 500 kWh per year onto the grid when energy prices averaged $0.25/kWh (a cost savings of $125), and where the average energy cost during times the EV was taking its 3500 kWh off the grid for charging was $0.03/kWh (a cost of $105). In this hypothetical, the net generation cost for the EV would be -$20 (or a $20 cost savings), before accounting for any capacity cost savings.

10.4.2 Technology Operating Profile

Electrification impacts on the grid will depend considerably on their load shape, which is the amount of energy consumed during different seasons of the year as well as during different hours of the day. Electrification load shapes differ substantially from one end-use to another. For example, electricity consumption for residential space heating is naturally concentrated in the winter, and often greater at night when outdoor temperatures are lowest. This pattern will be fairly similar on weekdays and weekends.[44] In contrast, electricity consumption for electrified industrial processes will typically be the same in all seasons of the year, and even relatively consistent across all operating hours of the day (e.g., similar across all 16 hours of a two-shift manufacturing facility). However, depending on whether the facility operates five, six or seven days a week, there could be significant differences between weekdays and weekends.

There can also be differences in load shapes between different kinds of technology used for a given electric end-use. For example, the shape of the electric load for space heating will be different for electric resistance heating, standard air source heat pumps, and cold climate air source heat pumps—as described below:

- For electric resistance heat, the consumption in any given hour is largely linearly related to outdoor temperature because the efficiency of resistance heat never changes.
- Heat pump efficiency declines as the outdoor temperature declines; thus, its consumption increases more quickly as outdoor temperatures drop. While it is still more efficient than electric resistance heat, the efficiency gain relative to resistance heat declines as the temperature declines.
- At a low enough outdoor temperature, heat pumps may no longer be able to meet the heating needs of the building and may need to rely on electric resistance back-up heat. The outdoor temperature at which that change-over occurs will depend on the heat pump.
- Standard air source heat pumps rely entirely on electric resistance back-up heat when the outdoor temperature drops below a certain point (e.g., below 5, 10, 20, or 30 degrees Fahrenheit, depending on the heat pump model).
- High performance, cold climate, air source heat pumps can perform at their stated nameplate capacity in heat pump mode down to 5 degrees Fahrenheit, and they can continue to provide some heat down to -10 or -15 degrees Fahrenheit or even lower (although at a lower efficiency).
- Ground source heat pumps can produce heat relatively efficiently regardless of outdoor air temperature.

Similarly, as discussed in 10.5.2 below, load shapes for EVs can be different depending on the extent to which customers rely on home chargers, have access to chargers at work, and the type of charger that they use (level 1, level 2 and/or direct current fast charging).

Finally, as discussed above as well as in 10.5.1, load shapes for a given electric end-use can vary significantly depending on rate design (e.g., whether customers pay time-varying rates or flat rates), as well as the extent to which their electrified loads are managed or controlled through DR programs.

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[44] There may be some differences between weekdays and weekends if customers set back thermostats during weekday work hours when no one is home.

10.4.3 Enabling of DR Capability

Many electrification measures can be managed by the host customer to minimize costs (if the host customer has the appropriate rate structure) and/or controlled through DR initiatives. Both customer load management and DR initiatives can reduce—potentially significantly—the generation and/or T&D capacity costs that electrification measures impose on the electric system.

If DR capabilities are enabled at the time the electrification measures are purchased or installed, the additional capacity, T&D, and/or reliability benefits should be included in cost-effectiveness assessments. The same is true of the storage resource capability of EVs with V2G capability. However, even if the DR and/or V2G storage capability is not enabled at the time of the electrification measure purchase or installation, there is a value associated with the latent capability of electrification measures to provide DR and/or storage capability to the grid in the future. That value, though potentially difficult to quantify, should be reflected in cost-effectiveness assessments of electrification.

10.4.4 Other Fuel Impacts

Electrification means substituting (i.e., increasing) electricity consumption for the consumption of other fuels, and therefore will increase electric system costs (with the possible exception of EVs with V2G capability, as discussed above.) While management or control of electrified loads can minimize the *magnitude* of the electric system cost increases associated with most electrification measures, it cannot eliminate them altogether. Thus, again with the possible exception of EVs with V2G capability, electrification measures are likely to be deemed cost-effective only if the benefits of their corresponding reductions in gasoline, diesel fuel, natural gas, fuel oil, propane and/or other fuels are included in a jurisdiction's BCA test.

> Electrification measures are likely to be deemed cost-effective only if the benefits of their corresponding reductions in gasoline, diesel fuel, natural gas, fuel oil, propane and/or other fuels are included in a jurisdiction's cost-effectiveness test and cost-effectiveness analyses.

As shown in Table 10-2, for jurisdictions that include other fuel impacts in their BCA tests (consistent with jurisdictional energy policies), it is important to recognize that the other energy system cost savings resulting from electrification can extend beyond just commodity (or fuel) savings. For example, when electrification lowers demand at times of gas system peak demand, it can help defer the potential for future capital investments to upgrade the gas transmission and/or distribution system infrastructure. There may be similar "capacity" savings associated with reduced infrastructure for distribution of petroleum products.

In addition, electrification of buildings can obviate the need for connecting those buildings to the natural gas distribution system (including installation of a gas meter), saving the cost of such connections. This can occur in the following example scenarios:

- In the case of new construction, when all end-uses that might otherwise have used natural gas—space heating, water heating, drying, cooking, etc.—are instead met entirely with electricity. In such cases, the builder would save the cost of connecting the building to the gas distribution system. Any ongoing fixed costs (meter reading, billing, etc.) of supplying natural gas to the home in subsequent years would also be avoided.
- In the case of fuel-switching existing buildings using fuel oil, propane, or other unregulated fuels to either (a) natural gas which is not currently locally available or (b) electricity which is already available at the building. In such cases, assessments of the relative cost-effectiveness of the

natural gas conversion should include consideration of the cost of bringing the gas distribution infrastructure to the building (whether relatively modest because gas is already "at the curb" or more substantial because the gas pipe would need to be brought to the town and then to the building) as well as ongoing fixed annual costs of supplying gas to the building.

10.4.5 Host Customer Non-Energy Impacts

Table 10-5 presents a summary of host customer NEIs that might potentially be created by electrification and EVs resources. These impacts can sometimes be in the form of benefits and sometimes costs. The presence, direction, and magnitude of electrification or EV NEIs will depend upon many factors, including the use case for the technologies, the type of host customer (low-income, residential, commercial, industrial), the host customer's needs, and the rate design in place.

Table 10-5 indicates whether the category of NEIs is typically a cost, a benefit, or either in most common applications. The actual direction of the impact, however, should be determined on a case-by-case basis.

Table 10-5. Potential Host Customer Non-Energy Impacts of Electrification and Electric Vehicles

Host Customer NEI	Electrification	EVs	Examples
Transaction costs	🔴	🟠	– Electrification: Application fees and processes – EVs: reduced need to stop to re-fuel when charging at home or work – EVs: increased time to re-fuel when charging on the road
Asset value	🟢	○	– Electrification: Increased building value
Productivity & operational flexibility	○	🟢	– EVs: Reduced O&M costs
Comfort	🟠	🟢	– Electrification: Thermal comfort may be better or worse – Electrification and EVs: Noise reduction
Health & safety	🟢	○	– Electrification: Reduced indoor air pollution
Empowerment & control	🟢	🟢	– Electrification and EVs: Psychological benefit from empowerment – Electrification and EVs: Energy independence
Satisfaction & pride	🟢	🟢	– Electrification and EVs: Contribution to addressing environmental issues

🟢 *= typically a benefit for this example;* 🔴 *= typically a cost for this example;* 🟠 *= either a benefit or cost for this example, depending upon the application of the resource;* ○ *= not relevant for this example.*

Key examples include:

- *Transaction Costs* can be reduced for owners of EVs. The ability to charge an EV at home and/or at work can eliminate the need to stop to refuel at gas stations. Conversely, driving range limitations can be considered a cost by EV customers because the much longer times required for recharging (relative to refueling a gas tank) can make it challenging to use such vehicles for some long-distance trips. These concerns may diminish as the range of EVs continues to improve and access to fast-charging facilities increases.
- *Operation and Maintenance* cost savings are an important benefit of EVs. EVs do not need oil changes and they tend to have fewer moving parts and therefore fewer mechanical problems as

the vehicle ages. O&M costs for EVs can be as much as half the costs for internal combustion engine driven vehicles (Logtenberg et al. 2018).

- *Heating Comfort* can be either a benefit or cost, depending on the type of heating system installed. For example, customers can experience comfort issues when buildings are retrofitted with heat pumps that are not well designed for their climates (ERS 2014). On the other hand, that concern can be addressed by matching heat pump selection to the climate (e.g., cold climate air source heat pumps or ground source heat pumps for cold climates). In addition, heat pumps with advanced features, such as variable speed inverter compressors, room temperature sensors, and variable air flow can improve comfort by keeping temperatures steadier.
- *Cooling/Dehumidification Comfort* is often a benefit. For example, heat pump water heaters both cool and dehumidify spaces. Also, when a heat pump is installed for space heating in homes that do not have (and would not otherwise have installed) cooling, the ability to also cool a room or house or business becomes an added amenity (though with added electric system costs).
- *Noise Reduction* is usually a benefit. EVs run more quietly than internal combustion engine driven vehicles. Advanced heat pumps that modulate the amount of heat provided to a room or building are often quieter than fossil fuel furnaces or boilers that are typically either 100 percent "on" (or 100 percent "off"). On the other hand, heat pump water heaters can be noisier than gas water heaters (though standard electric resistance water heaters are not).
- *Cooking Control* can be either a benefit or cost, depending on the type of electric cooking technology installed. Gas or propane cooktops allow instant heat as well as instant reaction to changes in the amount of heat being applied to a pot or pan. Electric coil cooktops cannot provide such instantaneous control; however, electric induction cooktops can. In addition, electric cooktops, whether coils or induction technology, can reach high heat—i.e. boil a large pot of water—more quickly than gas cooktops (Hope 2019 and Livchak et al. 2019).
- *Health and Safety* is generally a benefit of electrification. For example, electric appliances eliminate any indoor air pollution that would otherwise result from the use of fossil fuel burning appliances. That is perhaps most notable for fossil fuel cooktops, but also for heating and water heating appliances that are not properly vented, have cracked heat exchangers, and/or that experience back-drafting. Also, because electric induction cooktops use electromagnetism to produce heat and cook food in metal pots or pans, it is the pot or pan that becomes the "heater." When the pot or pan is removed from the cooktop there is no heat being produced, reducing chances of inadvertent fires or burns.
- *Driving Responsiveness* can be increased by EVs, which typically react more quickly than internal combustion engine-driven vehicles when accelerating and have very good torque (DOE 2020).

10.4.6 Air Emissions Impacts

Electrification measures can reduce net air emission impacts of both GHG and other pollutants, in cases where the marginal emissions from the electricity grid are low enough relative to the marginal emissions of the displaced fuel. Achieving aggressive carbon reduction goals may require a substantial amount of electrification because for some sectors, such as natural gas and transportation, there are few alternatives for significantly reducing GHG emissions at a reasonable cost (Synapse 2018).

As discussed in Chapter 5, DER air emission estimates should account for two important factors: (a) the time period for which the DER operates; and (b) the marginal emission rates of the utility system at the time when the DER operates. Further, the *Ensure Symmetry* principle requires accounting for both reduced and increased air emissions from DERs.

For electrification measures, there are several additional factors to account for regarding emission rates:

- There is a variety of fuels that can potentially be displaced by electrification (e.g., gasoline), and the marginal emission rates for those fuels should be accounted for.
- The efficiency of the baseline technology (e.g., an internal combustion engine vehicle or fossil fuel burning furnace, boiler, or water heater) will affect the fuel savings and therefore the air emission rates.
- The efficiency of the electric technology (e.g., the EV, heat pump, or heat pump water heater) will affect the fuel savings and therefore the air emission rates.

EVs with V2G capability can potentially have significant intra- and inter-day variation, making it especially important to account for the detailed time periods in which they are expected to operate.

10.4.7 Increased Electricity Costs

As discussed above, with the possible exception of EVs with V2G capability, electrification measures will increase electric system costs by increasing the amount of electric energy that needs to be produced and by adding to electric system and/or T&D system peak demands.

The extent to which increased consumption of electric energy adds cost to the system will be driven by a variety of factors including:

- The operating profiles of the electrification measures, including the extent to which electrification loads are coincident with current system and/or T&D peaks;
- The extent to which the operating profiles are affected by electric rate structures and/or DR measures designed to shift consumption to off-peak and lower cost hours;
- Variable energy costs, generation capacity costs, and T&D capacity costs, which often vary from season to season as well as during different times of day within the same region; and
- The amount of excess system generation capacity and/or excess T&D capacity on the grid.

All of these factors could be highly variable from one service territory to another.

Estimation of potential impacts on system and/or T&D peak demands entails consideration of more than just current grid load profiles. Jurisdictions should also consider how current peaks might change over time both absent electrification (e.g. "duck curve" effects associated with increasing deployment of solar generating capacity) and/or as a result of electrification (e.g. by adding enough electric heat to change a system from summer-peaking to winter-peaking).

In the case of electric heat pumps, it is also important to understand the potential for adding load during both winter peaks and summer peaks. Specifically, there may be cases where the heat pumps are adding cooling capacity to buildings that did not previously have it and would not have added it absent the electrification initiative.[45]

[45] It is important to not just assume that the baseline for a building currently without cooling would continue to be no cooling. Indeed, several evaluations of cold climate heat pump programs in New England found that many homes participating in such programs were initially interested in adding air conditioning and were convinced by the programs to purchase heat pumps instead of air conditioners (ERS 2014).

10.5 Common Challenges in Estimating Benefits and Costs

10.5.1 Seasonal and Daily Load Profiles

As discussed in the preceding sections, the impacts electrification measures will have on the grid will depend upon their use case, particularly their load shape. Load shapes have been used to estimate impacts in EE program cost-effectiveness analyses for decades. However, it is potentially more challenging for electrification measures than for efficiency measures.

This challenge can be addressed, in part, by utilizing end-use load shapes already in use for EE analyses, with the following potential modifications:

- To the extent that electrification is only partial—e.g. where electric heat pumps are only partially displacing fossil fuel heating, and the fossil fuel heating systems remain to help serve loads during very cold temperatures—EE load shapes will need to be modified.
- To the extent that any electrified loads will likely be modified by customers in response to new rate structures (e.g., time-varying rates)[46] and/or controlled through different forms of DR, load shapes will need to be modified.
- Finally, load shape assumptions will need to be developed for EVs whose charging patterns can be highly variable and influenced by rate design (SEPA 2019b), the availability of charging infrastructure for EVs, the fast-evolving technology (particularly around EV batteries), and other factors.

Overall, jurisdictions will need to develop assumptions to address each of these modifications or needs, and initial assumptions will likely involve significant uncertainty. However, that uncertainty can be mitigated over time as analyses are performed and used to update assumptions.

10.5.2 Charging Methods Used by EVs Consumers

The impacts EVs will have on the grid depend on the charging methods used by EV consumers:

- Level 1 chargers have relatively modest draws (up to 3 kW) of long duration (often 12 hours or more to fully charge a light-duty vehicle).
- Level 2 chargers can draw 3 to 22 kW and usually charge EVs in three to four hours.
- DC Fast Chargers (DCFC) have draws of 50 kW to 120 kW (Superchargers) and can charge most EVs to 80 percent of capacity within 30–60 minutes.
- Some light-duty vehicles are now accepting charging rates at up to 350 kW and the industry is currently developing standards for up to 1 MW charging for heavy-duty vehicles (SEPA 2019b).

Over an entire service territory, the differences in draw amount and duration of draw associated with the different charging options may be smoothed out if charging times are diversified across a large population of customers. However, high use of DCFC could reduce such diversification, at least on certain localized elements of the distribution system. This would cause the average EV load shape in some geographic areas to be different than it would be if rapid charging were not as widely used. In other words, large “spikes” in consumption from DCFC can potentially have significant effects on peak

[46] Which would lead to a different pattern of usage relative to an existing electric heating load shape that was based on a simpler rate structure.

demands of localized elements of the distribution system that serve them. (The average EV load shape for parts of the grid with high usage of rapid charging may be very different than for other parts of the grid or for the system as a whole.)

Even if use of a DCFC charging station were more evenly spread across all hours of the day (e.g., because it is serving large multi-family buildings, a truck stop, fleet vehicle facility, other institutional customers, or any other location with many vehicles charging at different times) the impact on the grid could be different than more dispersed use of level 1 and level 2 chargers as a result of the greater geographic concentration of charging.

This challenge can be addressed by considering the potential differences in grid impacts of different levels of charging, particularly the T&D system impacts, and estimating the expected mix of charging methods.[47] This assessment should include charging needs for large commercial fleets. To the extent that any adverse effects would be mitigated by rate design, DR, non-wires alternatives, and/or BTM storage, such mitigation should also be factored into analyses.

10.5.3 Impacts on Curtailment of Renewable Resources

In some areas, during some hours of the year, local generation from wind, solar and other generation resources (such as must-run generators) can exceed local area demand. If transmission capacity is insufficient to move all of the excess generation to other areas, renewable generation might need to be curtailed. To the extent that electrification measures are installed close to those transmission-constrained renewables, the curtailment of such renewable resources can be reduced. (See Section 5.3.)

The reduction in curtailments is clearly a benefit to the owners of the renewable resources because they will receive payments that they otherwise would not have received. Further, to the extent that electrification can utilize resources that otherwise would have been curtailed, the marginal cost to serve the electrified end-uses with such resources is zero. It is important to note, however, that from the broader electric system perspective there are no recognized cost reductions due to greater utilization of curtailed resources; there are just no additional costs to serve electrified load during the hours that renewables would otherwise have been curtailed. This is because no new generation needed to be constructed and no new variable costs need to be incurred to meet the needs of the electrified loads in the hours during which curtailments would otherwise have occurred. All else equal, however, electrification in such regions will be more cost-effective than in regions with no hours during which the marginal cost of electricity is zero. Geo-targeting of electrification to areas experiencing or forecast to experience significant renewables curtailment could be more cost-effective than system-wide electrification initiatives.

A potential exception to there being no electric system cost reductions resulting from reducing renewable energy curtailment would be if utilities and others are considering adding transmission and/or distribution capacity in order to reduce such curtailments. In such cases, electrification measures could provide a cost savings to the electric system if they displace or defer any planned transmission additions. Such avoidance or deferrals would improve the comparative economics of geo-targeted electrification even more. Capturing such

> Over an entire service territory, the differences in draw amount and duration of draw associated with the different charging options may be smoothed out if charging times are diversified across a large population of customers.

[47] Differences in charging efficiencies can also affect grid costs and should also be considered.

impacts in cost-effectiveness assessments of electrification measures will require:

- Identifying planned transmission investments;
- Estimating the costs and expecting timeline for such investments;
- Estimating the degree to which such investments could be deferred through increased local deployment of electrification measures and resulting reductions in renewables curtailment; and
- Assigning a value of investment deferral to each kW of added load from electrification (roughly speaking by dividing the value of investment deferral by the amount of electrification needed to produce the deferral).

10.6 Lost Revenues, Increased Revenues, and Rate Impacts

Lost revenues and potential rate impacts should not be included in cost-effectiveness analyses. Instead, DER lost revenues and rate impacts should be analyzed separately using rate, bill, and participation analyses. (See Section 2.3 and Appendix A.) In conducting BCAs, therefore, lost revenues should be identified so that they can be properly excluded from BCAs and properly included in rate, bill, and participation analyses.

In general, several key factors affect the extent to which DERs might create rate impacts:

- *Increases in utility system costs* will put upward pressure on rates.
- *Reductions in utility system costs* will put downward pressure on rates.
- *Reductions in sales* from DER resources will put upward pressure on rates.
- *Increases in sales* from DER resources will put downward pressure on rates.
- *Rate design* will affect the amount of lost or increased revenues created by the DER.

Electrification resources will typically increase electric utility system costs because of financial incentives or other program costs, and can increase utility system costs by increasing generation, transmission, and distribution costs (see Table 9-1). Electrification will typically reduce gas utility system costs by reducing fuel, variable O&M, and other gas costs (see Table 9-2).

Electrification will result in increased electricity sales and therefore increased electric utility revenues. The increase in electric revenues will exert downward pressure on electric rates by spreading the recovery of fixed costs over a broader base of sales. On the other hand, reduced consumption of natural gas will create upward pressure on natural gas rates because of the need to recover fixed and/or sunk costs over a smaller volume of gas sales.

Regulators and other stakeholders that are concerned about electrification impacts on gas utility rates could consider the following: (a) conduct a long-term gas utility rate, bill, and participation impact analysis, (b) seek and implement rate designs and electrification initiatives likely to mitigate equity concerns, (c) seek ways to expand customer participation, especially among low- and moderate-income customers, and (d) periodically review impacts as electrification technology deployment rates increase. Any such analyses should consider the reductions in electric utility rates as well as the increases in gas utility rates.

PART IV: BENEFIT-COST ANALYSIS FOR MULTIPLE DER TYPES

Overview

This part of the manual includes four chapters addressing different ways of combining multiple DER types, including:

- multiple on-site DER types, such as grid-integrated efficient buildings (GEBs);
- multiple DER types in a specific geographic location in the form of an NWS;
- multiple DER types across a utility service territory; and
- dynamic system planning practices that can be used to optimize DERs and alternative resources.

Each chapter includes a summary of key points, a description of how the multiple DER types might be used together, a discussion of key factors in determining benefits and costs, and guidance on how to address common challenges in determining benefits and costs.

Chapter 11 provides a case study of a GEB, with an illustration of how to consider interactive effects between DER types.

Chapter 12 provides a case study of an NWS, with an illustration of how to consider locational impacts of DER types.

Chapter 13 provides several examples of how to present BCA results to help prioritize DERs across a utility service territory.

Chapter 14 provides an overview of the evolving system planning practices, such as integrated distribution planning and integrated grid planning.

11. Multiple On-Site DERs

In some cases, utilities, customers, and/or third-parties may seek to install multiple on-site DERs, which may take form at the building, facility, campus, or neighborhood level. This chapter describes how to holistically account for the benefits and costs of multiple on-site DERs. It identifies key factors that affect those impacts and provides guidance on how to address challenges in determining benefits or costs.

11.1 Summary of Key Points

- Multiple on-site DERs might be installed in a variety of ways:
  - On a residential level, utilities are offering programs that give incentives to adopt multiple DER types that can then be used to benefit the customer and the grid.
  - On a residential and commercial level, grid-interactive efficient buildings (GEBs) have the potential to aggregate DERs and provide grid support at scale.
  - On a community level, microgrids and smart neighborhoods also have the potential to aggregate DERs and provide grid support at scale.
- The potential benefits and costs of multiple on-site DERs will depend on the type of DERs deployed, their capabilities, locational and temporal impacts, seasonal and daily load profiles, resource ownership and control of the DERs (i.e., level of dispatchability), and interactive effects across the DERs.
- Cost-effectiveness analyses of multiple on-site DERs should account for whether the initiative is new or is based on existing resources or programs with incremental benefits and costs.
- A key factor influencing cost-effectiveness calculations is the granularity of data desired and available for analysis. This is dependent on the site, existing infrastructure investments, and level of telemetry.

11.2 Introduction

Multiple (or aggregated) on-site DERs can take place in different forms, such as at the residential, commercial, and community levels—including microgrids and smart neighborhoods. These are each described below:

Residential and Commercial: Multiple DERs

On the residential level, the adoption of multiple DERs and other smart home technologies can control load. This approach enables utilities to leverage the combined effects of residential loads that may be too small or not flexible enough to address individually. Multiple DER programs or strategies to integrate technologies include Wi-Fi-enabled thermostats, appliances, other home devices (e.g., water heaters, refrigerators, air conditioners) and advanced metering infrastructure (AMI).

Examples include EE/DR integration and expanded integrated DER offerings in the form of residential solar-plus-storage offerings, bring-your-own-thermostat (BYOT) to bring-your-own-device (BYOD) DR programs, and broader smart home technology and EV adoption.[48] These technologies provide new customer engagement strategies for utilities and expanding the capabilities for customers to control and manage their load, and opportunities to provide value to the grid.

A GEB is defined as an energy efficient building with smart technologies characterized by the active use of DERs to optimize energy use for grid services, occupant needs and preferences, and cost reductions in a continuous and integrated way (DOE 2019c).

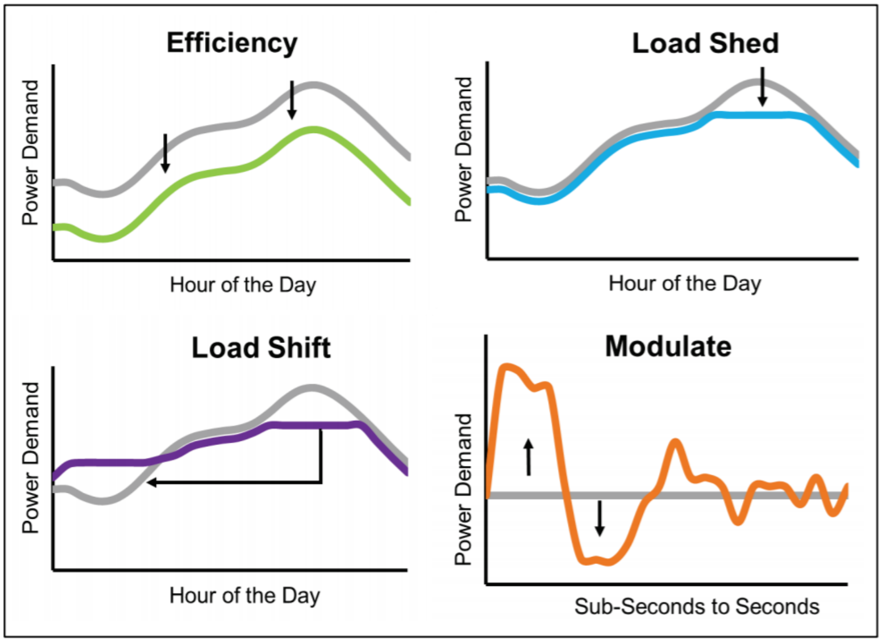
Commercial buildings can also serve as controllable loads that can provide value to grid for utilities. Buildings can account for up to 80 percent of the peak demand on the grid, indicating that their interconnection and interaction with the grid is not only important but potentially more cost-effective than residential DER integration due to the scale of grid support that they could provide (EIA 2018a).

Grid-interactive Efficient Buildings

GEBs are an example of the optimization that can occur from multiple DER types at one site or defined location, and the grid support that can be provided by residential and commercial buildings. A GEB is defined as an energy efficient building with smart technologies characterized by the active use of DERs to optimize energy use for grid services, occupant needs and preferences, and cost reductions in a continuous and integrated way (DOE 2019c). GEBs use efficient, connected, smart, and flexible resources such as energy storage, distributed generation, DR, and EE to efficiently shed, shift, and modulate load, thereby easing constraints on the grid and providing ancillary services as an option (DOE 2019a). (See Chapter 7.) Figure 11-1 illustrates changes in building load profiles for each of the operational modes.

[48] BYOT offerings allow customers to receive credit for their pre-approved and enrolled smart thermostat devices in exchange for enabling utility or third-party control to provide grid benefits. BYOD programs offer customers opportunities to participate in DR programs with the choice of multiple controllable devices, such as a thermostat, water heater, pool pump, EV charger, and batteries.

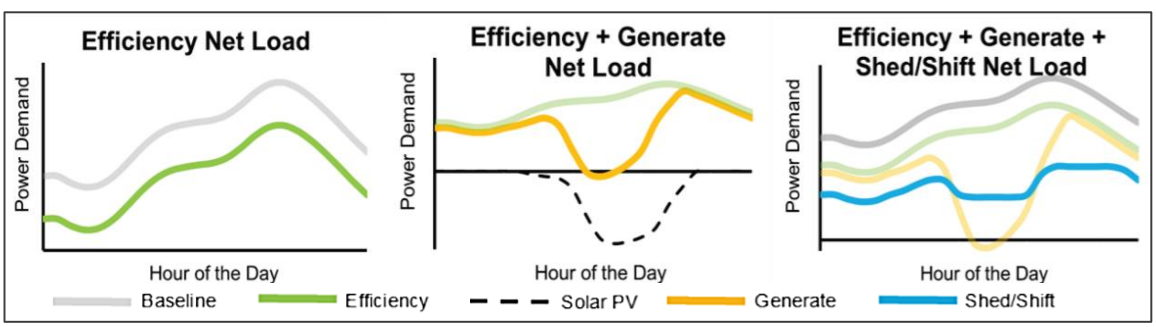
Figure 11-1. Grid-interactive Efficient Building Flexibility Load Curves



Source: DOE 2019a. Note the gray curve represents an example baseline building load and the green, blue, purple, and orange curves show the resulting building load.

GEBs use analytics supported by sensors and controls to optimize energy use for occupant preferences, utility price signals, and available on-site DERs. For example, Figure 11-2 illustrates representative daily average load profiles for a building by comparing scenarios including energy efficiency, on-site DPV generation, and a GEB scenario featuring an optimized blend of energy efficiency, solar PV, and demand flexibility (DOE 2019a). As seen in Figure 11-2, the addition of demand flexibility (represented as load-shedding/shifting) to efficiency (green line) and distributed generation (solar PV, black dotted line) results in a flattened and reduced building net load profile (blue line), which provides grid support (DOE 2019a).

Figure 11-2. Grid-interactive Efficient Building: Load Curves



Source: DOE 2019a.

Microgrids

Microgrids are composed of 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 it can connect or disconnect from the grid to operate in both grid-connected and "island" mode.

Microgrids can provide back-up power and added reliability and resilience to a single or networked system of loads within a defined boundary. Increasing disturbances caused by severe weather events, wildfires, and natural disasters are resulting in more emphasis on multiple on-site DERs such as microgrids as potential reliability and resilience solutions, especially for critical infrastructure (DOE 2019c and NARUC 2019).

Microgrids can contain a broad range of DER types, and configurations can range from a single customer microgrid to more complex designs that serve multiple customers, such as campus or neighborhood-style microgrids:

- A single customer microgrid is located BTM or at a point of common coupling that serves one customer or building's load and acts as a single controllable entity. Customers may install microgrids to meet their own needs and/or support neighboring or system needs.
- A campus microgrid is similar to a single customer microgrid except it serves multiple buildings that can be contiguous or non-contiguous. Universities, hospitals, and military bases are common examples.
- Multi-customer microgrids can serve multiple users' loads that are on contiguous or non-contiguous properties. The ownership, operation, and/or management of the microgrid assets vary between the customers and a third-party developer. Examples include mixed-use real estate development and data centers (SEPA 2019a).

Other variables that are useful in defining a microgrid include: size or capacity of the project, types of assets included in the project, primary operating mode, point of interconnection (BTM versus FOM), public rights of way, and on-site generation versus imported electricity (SEPA 2019a).

Smart Neighborhoods, Campuses, and Districts

There is a growing opportunity to expand the optimization of DER types integrated at a defined location across a set of homes or buildings into a smart neighborhood/community, campus, or district. Smart neighborhoods/communities will often include GEB characteristics such as energy efficient systems, smart appliances, connected devices, and flexible DERs (such as DPV and storage) that can be connected as a neighborhood-style microgrid (DOE 2019c). Campuses (such as universities, hospitals, or military bases) and districts (including mixed commercial, retail, and residential buildings) also can optimize demand flexibility and multiple DERs across buildings on a particular site.

11.3 Benefits and Costs of Multiple On-Site DERs

The potential benefits and costs of aggregated DERs on site will depend on the choice of DERs deployed. Chapter 4 provides descriptions of the potential benefits and costs of DERs (including utility-system, host customer, and societal impacts). Chapters 6–10 includes the benefits and costs for EE, DR, DG, storage, and electrification, each of which may be included as part of multiple on-site DERs. Benefits and costs will depend upon many factors, including the DER types used in the home or building(s), their size and layout, their operational patterns, and the existing capabilities at each site (i.e., the portfolio of passive and dispatchable resources).

The specific technologies utilized per site will affect their cost-effectiveness. Depending on the project and DER technologies used, not all benefit or cost categories may apply. Further, to assess the cost-effectiveness per defined location, accounting for other contributing factors is important. Such factors include locational and temporal values, the potential interactive effects of different DER types, resource ownership and control, and seasonal and daily load profiles. (See Chapter 5.)

Benefits and costs will depend upon many factors, including the DER types used in the home or building(s), their size and layout, their operational patterns, and the existing capabilities at each site (i.e., the portfolio of passive and dispatchable resources).

11.4 Key Factors that Affect Benefits and Costs

11.4.1 Integration and Cross-Coordination of Program Design

Integration of DERs at a defined location or into a single program has the potential to increase overall efficiencies and benefits, in addition to creating new value streams and/or value propositions.

Cost-effectiveness analysis should consider whether multiple on-site DERs are based on existing resources or programs, where incremental benefits and costs can be leveraged, or whether they include a new program or procurement. Program design cost efficiencies may be realized through reduced upfront investments, which can increase annual cost savings. This dynamic is especially prevalent when considering retrofitting current building stock to develop GEBs. Further, GEBs are most cost-effective on a larger scale where loads can be more easily smoothed to result in greater savings.

Program design factors affecting GEBs' cost-effectiveness include:

- location;
- measurement and verification;
- market integration (e.g., program administration, DER aggregation/communication, inverter interface, and cybersecurity); and
- codes and standards development.

For example, in the case of demand flexibility provided by GEBs, traditional utility program design and planning approaches may result in program savings estimates that differ greatly from forecasted planning estimates due to the time-sensitive value of grid services, as well as programs including measures/resources with long expected useful lives (10–15 years) (SEE Action 2020c). This challenge may be addressed through accounting for benefits across the full expected useful lives of resources and newer approaches to program design, such as pay-for-performance instead of one-time, upfront payments (SEE Action 2020c).

11.4.2 Determining All Host Customer Impacts

The different DERs' operational characteristics pose challenges to the utility program managers when examining the utility system but also have the potential to impact customers. (See Chapter 4 and Table 4-3, in addition to Chapters 6–9.) Determining host customer impacts, including non-energy impacts, will require additional considerations beyond those discussed earlier when analyzing multiple DERs and the scale or conditions of the site.

For example, there are a number of considerations to account for when examining host customer impacts for multiple DER types at the building level. Older and more complex buildings may have higher operating costs and may require larger upfront costs to interconnect and increase efficiency (RMI 2019). Building loads will also vary and have different use cases based on factors such as the nature of their use or type, in addition to existing HVAC systems, EV charging infrastructure, existing energy management systems, and other installed technologies. These factors will all affect customer costs and savings.

11.4.3 Existing Infrastructure Investments, Visibility, and Control

A key factor influencing BCA calculations for multiple on-site DERs is the granularity of data desired and available for analysis. Data availability depends upon the site, existing infrastructure investments, and level of telemetry. Establishing avoided cost profiles and measuring program impacts will depend on the level of granularity of available data (temporal and locational). Existing on-site technology may be limited in providing the level of data granularity desired for establishing avoided cost profiles, and measuring performance or program impacts, which can impact cost-effectiveness analysis. Such limitations will need to be understood by the jurisdiction and planned for upfront.

Improving data granularity may require different approaches/technologies, such as building energy management systems, AMI submeters, or load disaggregation. The need for technology capabilities to monitor and potentially control DERs at a site may require additional investment for the utility or customer and may ultimately impact the upfront costs and administrative fees for the site manager and the utility. Advancements in technology and broader adoption may continue to expand capabilities for obtaining granular data of multiple DERs at a site, helping to overcome this challenge over time.

11.5 Common Challenges in Determining Benefits and Costs

The installation of multiple on-site DERs is an emerging area of research, with common challenges in determining cost-effectiveness as projects and programs are implemented by utilities, customers, or third-party providers.

11.5.1 Locational and Temporal Value

The assessment of cost-effectiveness for multiple on-site DERs depends on where the DERs are located, when they generate or increase/reduce consumption, and the resulting benefits and costs. (See Sections 5.2 and 5.3.)

The locational value of DERs has significant implications for multiple on-site DERs, such as GEBs or microgrids. In the case of GEBs providing demand flexibility and the ability to adjust loads and provide local capacity savings, locational benefits are likely to be higher (SEE Action 2020c). Furthermore, locational impacts and their associated economic value should be modeled to account for transmission and generation system values (see Section 5.3). The analysis should account for the interactive effects between distribution and bulk power system impacts (SEE Action 2020c).

The temporal value of DERs also has significant implications for some of the primary benefits and costs of multiple on-site DERs: energy generation, generation capacity, transmission capacity, distribution capacity, and environmental benefits and losses, among others. For example, in a GEB with two or more

DER types providing demand flexibility, the combined load shape impacts on generation and T&D capacity demand should reasonably reflect the interaction of these resources with each other (SEE Action 2020c).

In sum, the benefits and costs of multiple DERs per site should be estimated using enough locational and temporal detail to adequately represent the DER operating patterns and consequent benefits and costs.

In sum, the benefits and costs of multiple DERs per site should be estimated using enough locational and temporal detail to adequately represent the DER operating patterns and consequent benefits and costs.

11.5.2 Interactive Effects

Different DER types can have interactive effects on each other, including effects on avoided costs and effects on kWh or kW impacts, and enabling other DERs. These interactive effects should be accounted for in the BCA of initiatives that promote multiple DER types per site, if such impacts are determined to be material.

- *Marginal System Costs*: When a large amount of DERs are installed in one region, they can affect the avoided costs of other DERs within that region. The best way to account for this effect is through dynamic system planning (see Chapter 14). In the absence of dynamic planning, different approaches can be used to approximate the interactive effects on avoided costs (see Section 5.4.1). In the case of initiatives promoting multiple on-site DERs, the interactive effects on marginal system costs are likely to be relatively small, until the initiatives reach high rates of deployment.
- *kWh and kW Effects*: When multiple DER types are deployed, the operation of one DER type might affect the kWh or kW impacts of other DER, depending on their types. In the case of initiatives that install multiple on-site DERs, it will be important to estimate the interactive effects that may occur due to their proximity and depending on the types of DERs (see Section 5.4.2). Evaluation efforts for these initiatives should specifically investigate how different DER types affect the kWh and kW impacts of other DERs, so that better information will be available over time.
- *Enabling Effects:* Some DERs can make it easier or more cost-effective to adopt other types of DERs. In the case of initiatives that install multiple on-site DERs, the initiative itself is designed to facilitate multiple DER types, and it is expected that some DERs will help make other DERs more cost-effective. For instance, in the case of GEBs, analysis can first capture major interactions between pairs of DERs, such as DR and EE, or DPV with on-site storage. Therefore, these enabling effects should be factored into the design of the initiative, and the cost-effectiveness analysis should account for that design. (See Section 5.4.3.)

11.6 Lost Revenues and Rate Impacts of Multiple On-Site DERs

Lost revenues and potential rate impacts should not be included in cost-effectiveness analyses. Instead, DER lost revenues and rate impacts should be analyzed separately using rate, bill, and participation analyses. (See Section 2.3 and Appendix A.) In conducting BCAs, therefore, lost revenues should be identified so that they can be properly excluded from BCAs and properly included in rate, bill, and participation analyses.

In general, several key factors affect the extent to which DERs might create rate impacts:

- *Increases in utility system costs* will put upward pressure on rates.
- *Reductions in utility system costs* will put downward pressure on rates.
- *Reductions in sales* from DER resources will put upward pressure on rates.
- *Increases in sales* from DER resources will put downward pressure on rates.
- *Rate design* will affect the amount of lost or increased revenues created by the DER.

The potential rate impacts of programs offering multiple on-site DERs will depend on many factors, including the choice of DERs deployed; the magnitude of DER savings, generation, and consumption; DER deployment; DER utility system costs; and utility system avoided costs.

Rate impact analyses of programs offering multiple on-site DERs should assess the rate impacts of all DER types in combination. This holistic approach will provide the best indication of the actual rate impacts on customers. (See Chapters 6–10 and Appendix A.)

11.7 Case Study: Commercial Grid-Interactive Efficient Building

This section provides an illustrative example of a GEB to demonstrate key factors and challenges of BCA for multiple on-site DERs. Interactive effects are highlighted for discussion, and in addition, real world project examples and further resources are included for further consideration.

11.7.1 Case Study Assumptions

This illustrative case study describes a program for commercial GEBs to provide demand flexibility benefits to the grid. The goal of the program is to integrate clean resources during system peak hours and meet jurisdiction goals to reduce GHG emissions. The utility provides performance compensation for occupants in the building that provide demand flexibility during system peak periods. The GEB program is provided by an investor-owned utility regulated by a commission.[49]

[49] The sources and types of information used are illustrative but are based on typical experience and data.

Commercial GEB Case Study Assumptions

DER Types: The GEB program includes the following BTM DERs:

- Energy efficiency (e.g., building envelope, HVAC, and lighting and controls)
- Demand response (e.g., direct load controls, programmable thermostats)
- Distributed photovoltaics
- Distributed storage systems

The Jurisdiction-Specific Test: The hypothetical jurisdiction's primary BCA test includes utility system impacts, host customer impacts, and GHG impacts.

Key Assumptions:

- *Non-coincident Peak:* the distribution feeder hosting the GEB has a peak demand that is non-coincident with the overall system peak (e.g., distribution feeder hosting the GEB peaks at 1:00-5:00pm, while system peaks from 5:00-9:00pm).
- *GHG Emissions Reduction:* the system-peak hours entail higher marginal emissions rates than the GEB, which allows the GEB to deliver GHG benefits.
- *DER Operating Profiles:* the GEB's BTM DERs operate in the following interactive ways:
    - Storage charges during the system off-peak hours, including any excess solar PV generation from the building, and discharges during system peak.
    - DR shifts load from on-peak system hours to off-peak system hours.
    - Solar helps meet on-site customer load, with any excess generation being used to charge the storage resource. Solar's benefits are concentrated during system off-peak hours, and its benefit to system peak diminishes as the sun sets unless paired with storage.
    - EE has a general downward trajectory on usage.

11.7.2 Case Study Benefit-Cost Analysis

Using the above JST and assumptions for this illustrative GEB program, the benefits and costs are examined below across an array of utility system, host customer, and societal impacts.

Table 11-1 presents the utility system impacts; Table 11-2 presents the host customer impacts; and Table 11-3 presents the societal impacts of this illustrative GEB program. The net impacts are presented in aggregate in Figure 11-3.

Table 11-1. Net Benefits and Costs of GEB Case Study: Utility System Impacts

Type	Utility System Impact	Cost or Benefit	Notes
Generation	Energy Generation	🟢	Significant generation benefits accrue in the form of: – Demand flexibility, as the GEB shifts building load away from system peak hours, with load-shifting also providing capacity during system peak times – Excess solar from PV is used to charge the GEB's storage systems during system off-peak hours, and storage systems are scheduled to discharge during system-peak hours – GEB using DR direct load control to shift load during system-peak hours to off-peak time
	Capacity	🟢	
	Environmental Compliance	🟢	
	RPS/CES Compliance	🟢	
	Market Price Effects	🟢	
	Ancillary Services	🟢	
Transmission	Transmission Capacity	🟢	Transmission benefits accrue as the GEB's combined DERs reduce delivery of central generation to customers (DPV helps meet on-site customer load, with any excess generation being leveraged by the storage system).
	Transmission System Losses	🟢	
Distribution	Distribution Capacity	🟢	Net benefits for distribution impacts accrue, even though peak demand for feeder is non-coincident with system peak. The net benefits would be greater if the distribution feeder hosting the GEB has a coincident peak with the system.
	Distribution System Losses	🟢	
	Distribution O&M	🟢	
	Distribution Voltage	🟢	
General	Financial Incentives	🔴	Benefits from reliability, resilience, and risk are outweighed by other general utility costs (financial and performance incentives, and administration costs) to net to an overall general utility cost in this example.
	Program Administration Costs	🔴	
	Utility Performance Incentives	○	
	DG tariffs	○	
	Credit and Collection Costs	🟢	
	Risk	🟢	
	Reliability	🟢	
	Resilience	🟢	

🟢 *= a benefit for this example.* 🔴 *= a cost for this example.* ○ *= not relevant for this example.*

Table 11-2. Net Benefits and Costs of GEB Case Study: Host Customer Impacts

Type	Host Customer Impact	Cost or Benefit	Notes
Host Customer	Host portion of DER costs	🟢	This example jurisdiction includes both host customer costs and benefits to ensure symmetry in treatment of impacts in the JST.
	Host transaction costs	🟢	
	Interconnection fees	🟢	
	Risk	🟢	
	Reliability	🟢	
	Resilience	🟢	
	Host Customer NEIs	🟢	

🟢 *= a benefit for this example.* 🔴 *= a cost for this example.* ○ *= not relevant for this example.*

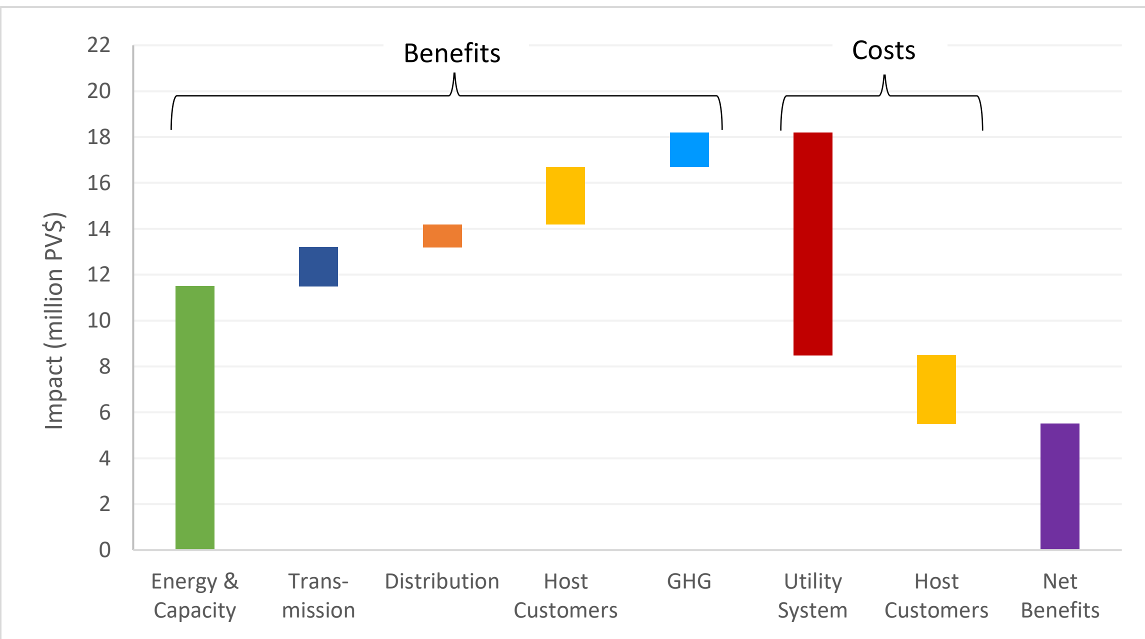
Table 11-3. Net Benefits and Costs of GEB Case Study: Societal Impacts

Type	Societal Impact	Cost or Benefit	Notes
Societal Impacts	GHG Emissions	●	GHG emissions reductions accrue as the GEB helps offset resources with higher marginal emission rates.
	Other Environmental	○	This example jurisdiction does not include these societal impacts in its JST based on its review of its applicable policies.
	Resilience	○	
	Economic and Jobs	○	
	Public Health	○	
	Low Income: Society	○	
	Energy Security	○	

● *= a benefit for this example.* ○ *= not relevant for this example.*

Figure 11-3 presents the utility system impacts, the host customer impacts, and the GHG impacts as required in this example jurisdiction's JST. As indicated, the combination of multiple on-site DERs in this GEB example results in an overall net benefit.

Figure 11-3. Example of Grid-Interactive Efficient Building Cost-Effectiveness



11.7.3 Key Challenge: Interactive Effects

Identifying interactive effects between DERs are a common challenge in BCAs for GEBs. The primary interactive effect of GEBs is the impact that each DER has on the magnitude of kW or kWh impacts of other DERs. This illustrative GEB case study considers major enabling interactions between pairs of DERs, such as DR and EE, or solar PV with on-site storage, to aid cost-effectiveness analysis. These interactive effects are illustrated in Figure 11-4.

Figure 11-4. Example of GEB Interactive Effects

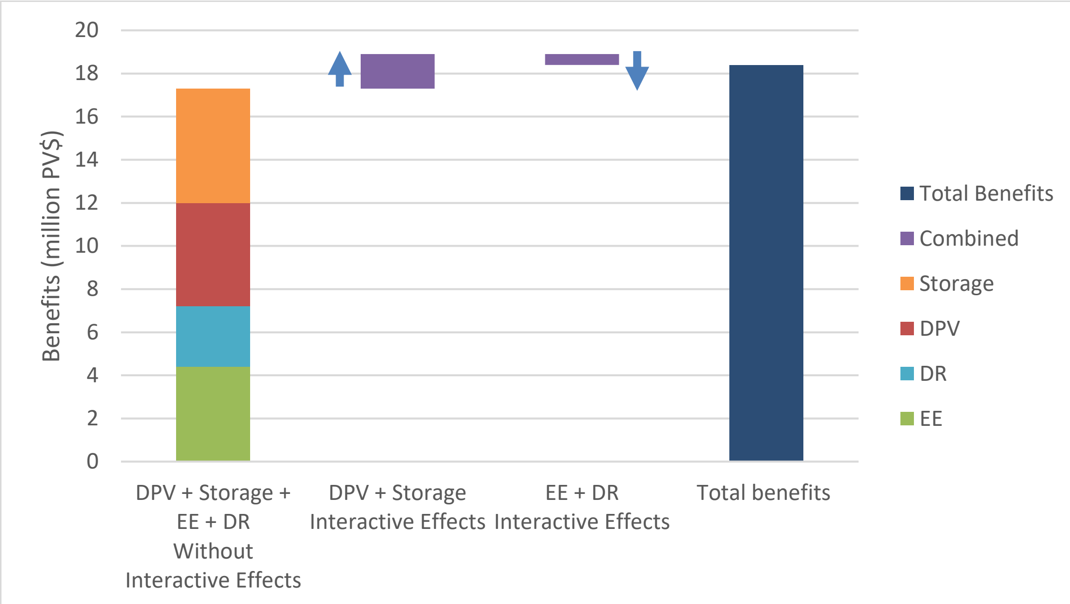


Figure 11-4 demonstrates how, in this GEB case study, accounting for interactive effects of DERs led to an increase in benefits. The left bar illustrates the sum of individual DER benefits without consideration of interactive effects. (See Section 5.4 for individual DER graphs.) This can be juxtaposed with the bar on total benefits with interactive effects (right bar), which illustrates the total benefits accrued due to the combination of DERs after accounting for interactive effects. Interactive effects can either enhance or reduce benefits, as illustrated in Figure 11-4, with distributed PV and storage as well as with EE and DR. Considerations of the interactive effects of these pairings include:

- Pairing solar PV with storage systems improves the PV's benefits by storing excess PV generation during periods of low electricity costs and/or demand and discharging from the storage device during periods of high electricity costs or demand.
- Combined DG and storage resources may influence the storage resource's dispatch pattern based on the performance of the DG resource (e.g., firming the capacity of a solar PV resource).
- Efficiency measures implemented in the building reduce the amount of demand flexibility capacity available to respond during events.
- Although not indicated in Figure 11-4, a building with DR resources (e.g., controllable thermostats, hot water heaters) could affect the dispatch parameters of a storage resource within the same building.

The text box below provides a real-world example of the dynamics of interactive effects. Additional information on GEB projects can be found in ACEEE 2019b, DOE 2019a, NEEP 2020, and SEE Action 2020b.

Portland General Electric's Smart Grid Test Bed Pilot and Demand Flexibility

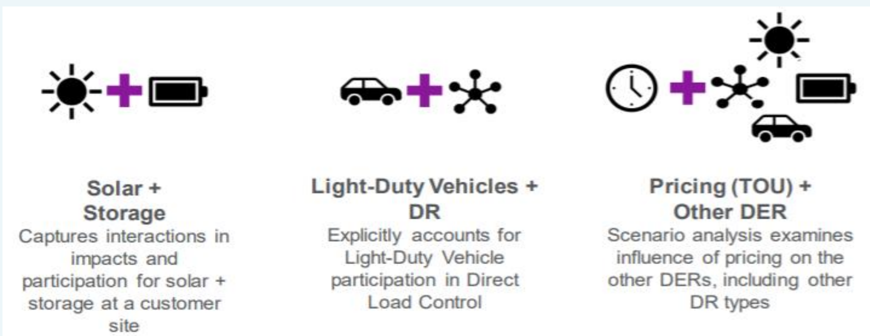
Interactive effects can be further considered through a real-world example. Portland General Electric (PGE) launched its Smart Grid Test Bed pilot in 2019 to test demand flexibility, including 69 MW in summer and 77 MW in winter, to address a 2021 capacity gap (PGE 2019). The pilot aims to integrate customer-sited smart grid technologies including smart thermostats, water heaters, electric vehicle chargers, and batteries for demand flexibility. The pilot includes over 20,000 customers in three Oregon neighborhoods (served by three distribution substations) (PGE 2020; SEE Action 2020b).

The pilot is focused on testing DR programs and smart-home technology incentives to build towards future initiatives (e.g., virtual power plants), as well as to accelerate customer-hosted DER adoption (PGE 2020). PGE also coordinates with the Energy Trust of Oregon on energy efficiency and rooftop solar. On the commercial side, PGE is testing direct installation of smart thermostats, EV charging, and storage (SEE Action 2020).

The pilot includes an opt-out peak time rebate (PTR) program, which includes day-ahead notice of called events and a rebate of $1.00 per kWh in reduced energy consumption during the event (PGE 2018; SEE Action 2020; PGE 2020). Additionally, the pilot will test how to shift customers to an opt-in load control program, utilize distribution substation-level data to inform DER modeling and distribution system planning, and explore DERs as NWSs (SEE Action 2020).

Included in its 2019 Integrated Resource Plan, PGE commissioned a comprehensive DER forecast study to enhance understanding of flexible load, including a focus on interactive effects between programs and resources (PLMA 2019). PGE plans to incorporate the analysis across the organization, including in its test bed activities. The *Distributed Resources & Flexible Load Study* (developed by Navigant/Guidehouse) included analysis on the interactive effects among resources, with interactive effects referring to "the effects of one distributed resource on the load shape of another distributed resource, beyond the simple addition of the two resources' load shapes" (Navigant/Guidehouse 2019). Figure 11-5 includes the interactive effects addressed in the study.

Figure 11-5. PGE 2019 Distributed Resources & Flexible Load Study – Interactive Effects Addressed



Source: Navigant/Guidehouse 2019.

The study highlights the following interactive effects:

- *Solar + storage* modeling captured interactions between resources at a single customer site and optimized for storage charging (from on-site PV) and discharging to maximize both peak shaving and customer value from bill management. The model simulations included hourly energy flows between the PV and energy storage systems, the customer's end-uses, and the grid. Simulations also optimized operations to maximize customer value, such as considering: different rate schedules (e.g., TOU pricing), customer segments, and varied solar and storage systems configurations. Value streams for resilience, direct load control, demand charge avoidance, TOU pricing arbitrage, and available rebates were considered when optimizing host customer impacts. Assumed baseline load shape not affected by behavior change.
- *Light-Duty Vehicles (LDV) and DR* modeling focused on the participation of LDV in a direct-load control DR program for aggregate peak reduction.
- *Pricing (TOU) and Other DER* modeling focused on the influence of TOU pricing on DR, solar PV, and LDV:
  - DR modeling considered TOU participation's impact on other DR programs.
  - DPV and storage modeling optimized storage charging and discharging to optimize customer bill savings.
  - LDV modeling assumed an average electricity cost decrease due to off-peak EV charging. Modeling also considered the impacts of TOU pricing on EVs, including on total customer cost of ownership (relative to an internal combustion engine vehicle), and the impacts of shifting charging to off-peak.

(Navigant/Guidehouse 2019 and Navigant/Guidehouse 2020)

12. Non-Wires Solutions

Utilities and others sometimes seek to install multiple DER types in a specific geographic area for the purpose of deferring or avoiding new investments in distribution or transmission systems. This chapter describes the benefits and costs most relevant to such a non-wires solution (NWS). It identifies key factors that affect NWS impacts and provides guidance on addressing common challenges in determining NWS benefits and costs.

12.1 Summary of Key Points

- NWSs include initiatives where utilities or others seek to install multiple DER types in a specific geographic area for the purpose of deferring or avoiding new investments in distribution or transmission systems.
- Cost-effectiveness analyses of NWS initiatives should account for the specific use case of the initiative, including the transmission or distribution upgrade being deferred, the length of deferral, the mix of DERs producing the deferral, and a range of other factors.
- The ability of an NWS initiative to defer transmission or distribution costs can shift depending on changing loads and load forecasts. Much of the option value of an NWS initiative is linked to the extent to which forecasted load growth ultimately materializes.
- Locational values of T&D impacts are among the driving factors behind the NWS, and therefore should be accounted for in NWS BCAs.
- Cost-effectiveness analyses of NWS initiatives should accurately forecast customer adoption and participation because risks from not meeting requirements pose challenges to the system.
- Whether an NWS initiative is new or is based on existing resources or programs with incremental benefits and costs should be accounted for in the NWS BCA.
- Cost-effectiveness analyses of NWS initiatives should account for interactive effects of DER types, especially the interactive effects on the total kW and kWh impacts of the DERs.
- NWS initiatives may have broader impacts on the utility system—beyond the avoided T&D costs. Cost-effectiveness analyses of NWS initiatives should account for all relevant impacts included in a jurisdiction's JST.

This manual uses the term "non-wires solution" to refer to all of these applications and defines NWS as "an electricity grid investment or project that uses non-traditional T&D solutions, such as distributed generation, energy storage, energy efficiency, demand response, and grid software and controls, to defer or replace the need for specific equipment upgrades, such as T&D lines or transformers, by reducing load at a substation or circuit level" (Navigant 2017).

12.2 Introduction

The concept of deploying DERs in specific geographic locations in order to defer or displace investment in transmission and/or distribution system upgrades has been referred to as: "targeted demand-side management," "geo-targeting," "non-wires alternative," "non-transmission alternative," and "non-wires solution." This manual uses the term "non-wires solution" to refer to all of these applications and defines NWS as "an electricity grid investment or project that uses non-traditional T&D solutions, such as distributed generation, energy storage, energy efficiency, demand response, and grid software and controls, to defer or replace the need for specific equipment upgrades, such as T&D lines or transformers, by reducing load at a substation or circuit level" (Navigant 2017).[50] While DERs can be located in any area and provide benefits to both the transmission and distribution grids, they are considered an NWS when specifically associated with the intentional deferral or replacement of utility T&D infrastructure upgrades.

NWSs can come in different sizes, have different deferral objectives, and utilize different DER technologies:

- *NWS Example 1: Geo-Targeted Existing EE & DR Programs:* Leveraging 300 kW EE and DR via existing customer programs that include resources such as Wi-Fi-enabled thermostats, heat pump water heaters, and window air conditioners to defer a substation feeder upgrade.
- *NWS Example 2: Large FOM Battery Storage*: Installing a 2 MW, 8 MWh battery system to defer distribution line upgrades and address thermal constraints on a feeder.
- *NWS Example 3: Combined FOM and BTM DERs:* Leveraging 52 MW of utility and customer-side resources such as EE, DR, DG (such as solar PV), and energy storage, among others, to defer a new substation upgrade.

This chapter discusses how the different characteristics of an NWS can affect its cost-effectiveness. The chapter focuses on electric NWSs, but the concepts apply equally to non-pipe solutions for gas utilities.

12.3 Benefits and Costs of Non-Wires Solutions

The potential benefits and costs of an NWS investment or project will depend on the choice of DERs deployed. (See Chapter 4.) Chapters 6–10 describe the benefits and costs for specific DERs, including EE, DR, DG, storage, and electrification, each of which may be a component of an NWS. This chapter provides guidance on how the cost-effectiveness of multiple DER types should be considered in the context of an NWS.

Depending on the NWS project and DER technology utilized, not all benefit or cost categories may apply. Additionally, as outlined in Chapter 5, conducting a BCA for an NWS project involves addressing other

[50] NWSs differ from virtual power plants (VPP) and microgrids. VPPs rely on software and advanced communication systems to aggregate, control, dispatch, plan, and optimize a suite of DERs to provide services similar to a conventional power plant. Microgrids comprise 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 it can connect or disconnect from the grid to operate in both grid-connected and "island" mode. Some NWS projects include VPPs and microgrids, which have the potential to reduce constraints on existing T&D infrastructure and help avoid the needs for system upgrades. However, a distinction can be drawn based on the purpose and goals of a project. NWSs covered in this manual refer to projects that defer or replace grid infrastructure upgrades, while VPPs and microgrids are traditionally developed for a variety of other purposes (E4TheFuture, PLMA, SEPA 2018).

contributing factors such as the characteristics of the infrastructure constraint, NWS technology characteristics, and locational and temporal values, among others.

12.4 Key Factors that Affect Benefits and Costs

12.4.1 Characteristics of Infrastructure Constraint

NWS cost-effectiveness depends on various infrastructure constraints, including the specific T&D infrastructure constraint, the size of constraint, and the season and time of constraint.

- *T&D infrastructure:* An NWS can be targeted to any element of the T&D system, such as a single transformer serving one large building, a substation, or a high-voltage transmission line serving a broader regional need. The specific constraint will impact cost-effectiveness: all else equal (including the cost of the NWS), the more expensive the traditional solution (per kW) the greater the benefit of the NWS deferral.[51]
- *Constraint size:* NWS cost-effectiveness will also depend on the size (both time duration and MW) of the specific constraint. For instance, an NWS could seek to address a limited summer peak capacity constraint or a broader regional load capacity growth forecast.
- *Season and time:* The season and time of the T&D peak being addressed will also impact cost-effectiveness, because DERs operate at different times depending on the season and/or time of day. An NWS will provide greater system peak benefits if the included DERs' operational patterns align with the system peak because peak reduction achieved locally will also have value at the system level. Furthermore, an NWS can target different deferral time horizons of a T&D investment: short-term deferral (1–3 years), longer-term deferral (5–10 years), or complete displacement (at least for the foreseeable future). All else equal, the longer an NWS deferral, the greater the benefit. The number of years of deferral of an NWS project can also shift while the NWS is being deployed as forecasts of the T&D need are updated and refined (see Section 12.5). Such changes can either move up the expected need date or push it back, where typically the latter is the case and allows for additional time to further refine forecasts.

12.4.2 Selected Technology Characteristics and Capabilities

NWSs can include a broad range of DER types, sizes/capacities, and locations (FOM or BTM). Diverse technologies included in an NWS will have different benefits and costs that they can simultaneously provide while addressing localized T&D constraints. For example, DR often only provides T&D and potentially system peak savings. In contrast, DERs such as storage and vehicles with V2G capabilities can provide T&D peak savings, system peak savings, and potentially economic dispatch capabilities to shift consumption from high energy cost hours to lower cost hours. Other DERs such as EE and DG can also provide energy benefits, in addition to T&D and system peak savings.

An NWS can include a single DER, but NWSs more commonly include multiple DERs. An NWS can be based on a combination of different technologies with varying predictability when it comes to their net

[51] A critical component of cost-effectiveness analysis for NWS includes T&D capacity benefits, with the value of (active) deferrals per peak kW typically based on the actual deferral value of the avoided transmission or distribution project (e.g. the amount of revenue requirement that will not be collected if the wires investment is deferred for a certain number of years). There is often a minimum cost threshold for T&D projects to be considered for NWA solutions; therefore, the value of active deferrals is typically higher than passive deferrals.

loading. When these DERs are combined as an integrated solution, it will be important to account for the performance of different DERs in relation to other inputs such as customer participation (in the case of DR), weather (e.g., solar PV performance), and resource ownership and control (e.g., storage systems and their operational profile). (See Chapters 6–10.) Beyond understanding each DER that may be included in an NWS portfolio, it is important to understand how the portfolio will perform in aggregate in response to the needs of the T&D constraint.

12.4.3 Existing Programs or Procurement

In some cases, cost-effectiveness analyses must consider whether an NWS portfolio includes DER types that are based on an existing program or a new program. If a DER is based on existing programs (such as existing EE and DR programs) that can be leveraged to alleviate localized T&D constraints, the BCA should include the NWS impacts that are *incremental* to the existing programs. For new NWS programs, the BCA should include the *entire* cost of the NWS program.

If there are existing system-wide EE or DR programs included in an NWS, for example, it is easier and less expensive (all else equal) to leverage existing trained contractors with technology and customer expertise, relationships with trade allies, marketing materials, etc., to further recruit customers into an existing program. However, it is also important to consider the fact that the impacts associated with the existing programs will be experienced regardless of the NWS. The net effect of these two factors will depend on the DER initiative, its historical deployment rates in the geo-targeted area, and a range of other factors. (See Section 12.5 for additional discussion on customer adoption and participation.)

12.4.4 Accounting for Other Electric Utility System and Non-Electric Impacts

In addition to T&D deferral benefits, NWS cost-effectiveness should account for other electric utility system and non-electric impacts, to the extent they are relevant to a jurisdiction given its applicable energy policy goals (see Chapters 2 and 3). Many DERs deployed as part of an NWS will not only affect the localized T&D constraint targeted by the NWS, but also costs associated with other aspects of the electric system. All such electric system impacts should be included in assessments of the cost-effectiveness of an NWS (see Chapter 4).

Many DERS deployed as part of an NWS will also have impacts beyond the electric system, including host customer consumption of other fuels, other non-energy impacts experienced by host customers and a variety of societal impacts such as changes in GHG emissions. All such non-electric system impacts that are included in the jurisdiction's primary cost-effectiveness test should also be reflected in cost-effectiveness assessments of NWSs (see Chapter 4). (See Chapters 6–10 for guidance on individual DERs.)

12.5 Common Challenges in Determining Benefits and Costs

12.5.1 Determining Locational and Temporal Value of DERs in an NWS

DER benefits and costs depend significantly on where they are located within the system and when they generate or increase/reduce consumption. The locational value of DERs has significant implications for T&D impacts, and therefore, is a primary criterion when planning, implementing, and evaluating an NWS portfolio. (See Sections 5.2–5.3.)

Different approaches exist today for calculating locational value, which include a more site-specific approach versus a more system-wide approach. The temporal value of DERs also has implications for several important impacts, including: energy, generation capacity, transmission capacity, distribution capacity, and environmental impacts. (See Sections 5.2 and 5.3.)

> The locational value of DERs has significant implications for T&D impacts, and therefore, is a primary criterion when planning, implementing, and evaluating an NWS portfolio.

Utilities and others will need to consider the granularity of available data (temporal and locational) for the purpose of properly assessing and assigning a numerical value to a location under evaluation. The accuracy and confidence of determining locational and temporal values is dependent on the data used to inform the analysis. For many utilities, the ability to gather and leverage granular data may be limited by existing infrastructure, software capabilities, and devices along the grid.

In sum, the benefits and costs of NWSs should be estimated using sufficient locational and temporal detail to adequately represent the DER operating patterns and consequent benefits and costs.

12.5.2 Accounting for Option Value and Determining Project Lifetimes

Due to the nature of T&D deferrals and uncertainty of load forecasts, it can be challenging to identify the number of years that T&D investments will be deferred by an NWS. This deferral can shift over time depending on changing load forecasts independently of the NWS (e.g., due to economic variability). For example, if the proposed solution is planned for a 5-year deferral, an unexpected benefit may arise if the proposed solution ultimately provides 10 years of deferral, and vice versa. Much of the option value is linked to load forecasting and the extent to which forecasted load growth ultimately materializes.

Load forecasts tend to be more uncertain and less accurate the further out they go in time. In these situations, DERs (such as EE or DR) deployed in an NWS can provide the opportunity to recalibrate load forecasts over time. This occurs due to the ability to incrementally implement an NWS portfolio (e.g., a project manager can implement EE and DR first, followed by energy storage, or recruit participants gradually for participation in a DR program) without high upfront deployment costs. As load forecasts decrease or increase in relation to the T&D capacity constraint, DER deployment can be adjusted. This modular nature of DER deployment can buy time to reassess needs (and options for meeting those needs) in a way that is often not possible with less modular capital investments in the T&D system. This flexibility provides value to the utility system.

12.5.3 Interactive Effects

Different DER types can have interactive effects on each other, including effects on avoided costs and effects on kWh or kW impacts, and enabling other DERs. It is important that these interactive effects be accounted for when assessing the cost-effectiveness of NWS initiatives, if such impacts are determined to be material. In theory, the benefits and costs of an NWS would not be different than the benefits and costs of the multiple DERs that compose the NWS, with interactive effects considered. The objectives of an NWS—to defer or displace investment in transmission and/or distribution system upgrades—require clear definition of both how DERs will be operated and the deferred or avoided infrastructure investment cost.

- *Marginal System Costs.* When large numbers of DERs are installed in one region, they can affect the avoided costs of other DERs within that region. The best way to account for this effect is through dynamic system planning (see Chapter 14). In the absence of dynamic planning, different approaches can be used to approximate the interactive effects on avoided costs (see Section 5.4.1). In the case of NWS initiatives, the interactive effects on avoided costs are likely to be small, unless and until the initiatives reach high rates of deployment.

- *kWh and kW Effects*. When multiple DER types are deployed, the operation of one DER type might affect the kWh or kW impacts of other DER types. In the case of NWS initiatives, it is possible that the operation of one DER will affect the kWh or kW impacts of another type because of their proximity. This is especially true for storage resources that could be dispatched in a way that accounts for the operation of other DERs. For NWS initiatives, therefore, it may be important to estimate these interactive effects. Evaluation efforts for these initiatives should specifically investigate how different DER types affect the kWh and kW impacts of other DERs, so that better information will be available over time. (See Section 5.4.2.)
- *Enabling Effects*. Some DERs can make it easier or more cost-effective to adopt other types of DERs. In the case of NWS initiatives, the initiative itself is designed to include multiple DER types, and it is expected that some DERs will help make other DERs more cost-effective. Therefore, these enabling effects should be factored into the design of NWS initiatives, and the cost-effectiveness analysis should account for that design. (See Section 5.4.3.)

12.5.4 Evaluating and Measuring NWS Impacts

Identifying both baseline forecasts and incremental impacts of NWSs can sometimes be challenging. The forecast used to identify the T&D capacity need must be the same as the forecast from which geo-targeted DER deployment increases will be measured for costs.

For example, consider a substation upgrade that was forecast to be needed five years from now. The forecast was based on historical localized load growth during a time when system-wide EE programs were producing 1.0 percent peak savings per year. However, the utility is now planning for 1.5 percent new peak savings per year from system-wide EE programs (and any additional geo-targeted EE is measured relative to that new 1.5 percent level). In this case, the resources needed to defer the substation upgrade would inappropriately appear to be greater and more extensive (and therefore more expensive) than they should be because the forecast need will have omitted system savings of 0.5 percent per year.

Additionally, in order to assign benefits and costs to the NWS, the incremental impacts of geo-targeted DERs must be measured relative to expected system-wide DER initiatives. Measurement options to account for this include strategies to ensure NWS DER adoption is additive and properly counted as incremental. An example strategy would be comparing the anticipated participation rates of the NWS in the geo-targeted area to account for historical DER participation rates in the same area with existing system-wide programs.

12.5.5 Accounting for System Reliability and Risk

Uncertainty of DER performance poses potential risk to the utility system, particularly when the DERs are used to defer a specific transmission or distribution asset. This risk is a countervailing effect to option value (see Section 12.5.1). If DERs do not perform when needed along the grid and consequently do not alleviate the identified grid constraint, this poses risk to the grid operator and the customers served. The variability and intermittent nature of DERs can add greater uncertainty into load forecasting and operation of the system. Utilities may thus perceive a risk when relying upon DERs to meet a system need compared to a traditional solution. For example, as discussed above, an NWS comprising customer-side load reductions may fail if customer recruitment and participation levels are not met. Likewise, a storage system may have construction delays or not perform at the required level to meet the NWS need. If an NWS does not perform as needed, the utility may face reliability penalties. When assessing the risk impacts of a DER, the net risk impacts should be applied, accounting for both the risk benefits and risk costs.

This risk of non-performing DERs can be mitigated as follows:

- One strategy entails modular deployment of DERs with continuous check-ins on progress and whether those DERs are meeting goals.
- Another strategy includes a “no-regrets” strategy, by deploying DERs that have numerous other benefits beyond addressing grid constraints.

The assessment of risk assumed in a BCA will depend on the approach used by the NWS planner and operator.

When NWSs are based on existing or new customer-sited DER programs, it is critical to accurately forecast customer adoption. Some customer-sited DERs (such as DR, BTM storage, and V2G) for NWSs require customers and operators to understand their dispatch commitments, but risks from customers failing performance requirements are difficult to predict and quantify. For example, customers participating in DR programs are often incentivized to participate, while not as many customers receive penalties for failing to meet commitments. In the case of an NWS depending on customer resources to perform during critical times, the costs for not performing may be much higher to the utility in the form of outage duration and frequency cost impacts.

Another option is to establish penalties in the developers’ contracts for DER procurement. A similar option is to establish utility performance incentives to ensure that the utility will successfully procure the DERs or compensate customers for what is not procured. These mechanisms to address risk should be incorporated into the design of the NWS program and into the BCA for that program.

12.6 Lost Revenues and Rate Impacts for Non-Wires Solutions

Lost revenues and potential rate impacts should not be included in cost-effectiveness analyses. Instead, DER lost revenues and rate impacts should be analyzed separately using rate, bill, and participation analyses. (See Section 2.3 and Appendix A.) In conducting BCAs, therefore, lost revenues should be identified so that they can be properly excluded from BCAs and properly included in rate, bill, and participation analyses.

In general, several key factors affect the extent to which DERs might create rate impacts:

- *Increases in utility system costs* will put upward pressure on rates.
- *Reductions in utility system costs* will put downward pressure on rates.
- *Reductions in sales* from DER resources will put upward pressure on rates.
- *Increases in sales* from DER resources will put downward pressure on rates.
- *Rate design* will affect the amount of lost or increased revenues created by the DER.

The potential rate impacts of NWS initiatives will depend on many factors, including the choice of DERs deployed; the magnitude of DER savings, generation, and consumption; the DER deployment; the DER utility system costs; and the utility system benefits.

Rate impact analyses of NWS initiatives should assess the rate impacts of all DER types in combination. This holistic approach will provide the best indication of the actual rate impacts on customers. (See Chapters 6–10 and Appendix A.)

12.7 Case Study: Non-Wires Solution

The objective of this case study is to demonstrate the cost-effectiveness analysis of multiple DER types in a specific geographic area, deployed for the purpose of deferring or avoiding new investments in distribution or transmission systems.

12.7.1 Case Study Assumptions

In this illustrative scenario, a utility is facing the need to upgrade significant infrastructure due to distribution capacity constraints identified on parts of the system in a geographic area. The utility plans to integrate DERs to serve as an NWS in place of the infrastructure upgrade. The constraint area is densely populated with residential and commercial customers. The geographic area is in an investor-owned utility's service territory regulated by a commission.[52]

Non-Wires Solution Case Study Assumptions

DER Types: The NWS plan includes the following BTM DERs in residential and commercial buildings:

- Energy efficiency measures (e.g., lighting and controls)
- Demand response (e.g., Wi-Fi-enabled thermostats)
- Distributed photovoltaics
- Distributed storage systems

The Jurisdiction-Specific Test: The hypothetical jurisdiction's primary BCA test includes utility system impacts, host customer impacts, and GHG impacts.

Key Assumptions:

- *Non-Coincident Peak:* The distribution need is non-coincident with the overall system peak (e.g., the constrained distribution feeder peaks from 1:00–5:00 pm, while system peaks from 5:00–9:00 pm).
- *GHG Emissions Reduction:* The system-peak hours entail higher marginal emissions rates than the NWS, which allows the NWS to deliver GHG benefits.
- *DER Operating Profiles:* The NWS DERs operate in the following ways:
    - All DERs are operated to reduce the distribution peak, and some can reduce the system peak as well.
    - Storage discharges during the distribution peak hours and charges during the system off-peak hours.
    - DR reduces demand during distribution peak periods and/or shifts load from distribution peak periods to system off-peak periods.
    - Distributed PV resources generate during distribution peak periods and during a portion of system peak periods.
    - EE helps to reduce demand during distribution peak periods, as well as system peak periods.

[52] The sources and types of information used are hypothetical/illustrative but are based on actual/typical experience and data.

12.7.2 Case Study Benefit-Cost Analysis

Using the above JST and assumptions for this illustrative NWS program, the benefits and costs are examined below across an array of utility system, host customer, and societal impacts.

Table 12-1 presents the utility system impacts; Table 12-2 presents the host customer impacts; and Table 12-3 presents the societal impacts of this illustrative NWS program. The net impacts are presented in aggregate in Figure 12-1.

Table 12-1. Net Benefits and Costs of NWS Case Study: Utility System Impacts

Type	Utility System Impact	Cost or Benefit	Notes
Generation	Energy Generation	🟢	Energy generation benefits occur as a result of the reduced energy consumption due to the DERs. Generation capacity benefits occur because the NWS includes EE savings and DPV output that overlap with system generation peak. However, the DR and storage resources will be operated primarily to reduce distribution system peaks, and therefore might provide less generation capacity benefit than other combinations of DERs would.
	Capacity	🟢	
	Environmental Compliance	🟢	
	RPS/CES Compliance	🟢	
	Market Price Effects	🟢	
	Ancillary Services	🔴	
Transmission	Transmission Capacity	🟢	Some transmission benefits result from the reduced delivery of central generation to customers.
	Transmission System Losses	🟢	
Distribution	Distribution Capacity	🟢	The largest benefit of the NWS is the direct benefits of geo-targeting DERs (operating at the necessary time) to alleviate distribution constraints.
	Distribution System Losses	🟢	
	Distribution O&M	🟢	
	Distribution Voltage	🟢	
General	Financial Incentives	🔴	Benefits from reliability, resilience, and risk are outweighed by other general utility costs (financial and performance incentives, and administration costs) to net to an overall general utility cost in this example.
	Program Administration Costs	🔴	
	Utility Performance Incentives	○	
	DG tariffs	○	
	Credit and Collection Costs	🟢	
	Risk	🟢	
	Reliability	🟢	
	Resilience	🟢	

🟢 *= typically a benefit for this example;* 🔴 *= typically a cost for this example;* ○ *= not relevant for this example.*

Table 12-2. Net benefits and Costs of NWS Case Study: Host Customer Impacts

Type	Host Customer Impact	Cost or Benefit	Notes
Host Customer	Host portion of DER costs	●	This example jurisdiction includes both host customer costs and benefits to ensure symmetry in treatment of impacts in the JST.
	Host transaction costs	●	
	Interconnection fees	●	
	Risk	●	
	Reliability	●	
	Resilience	●	
	Host Customer NEIs	●	
	-- Low-income NEIs	●	

● *= typically a benefit for this example;* ● *= typically a cost for this example;* ○ *= not relevant for this example.*

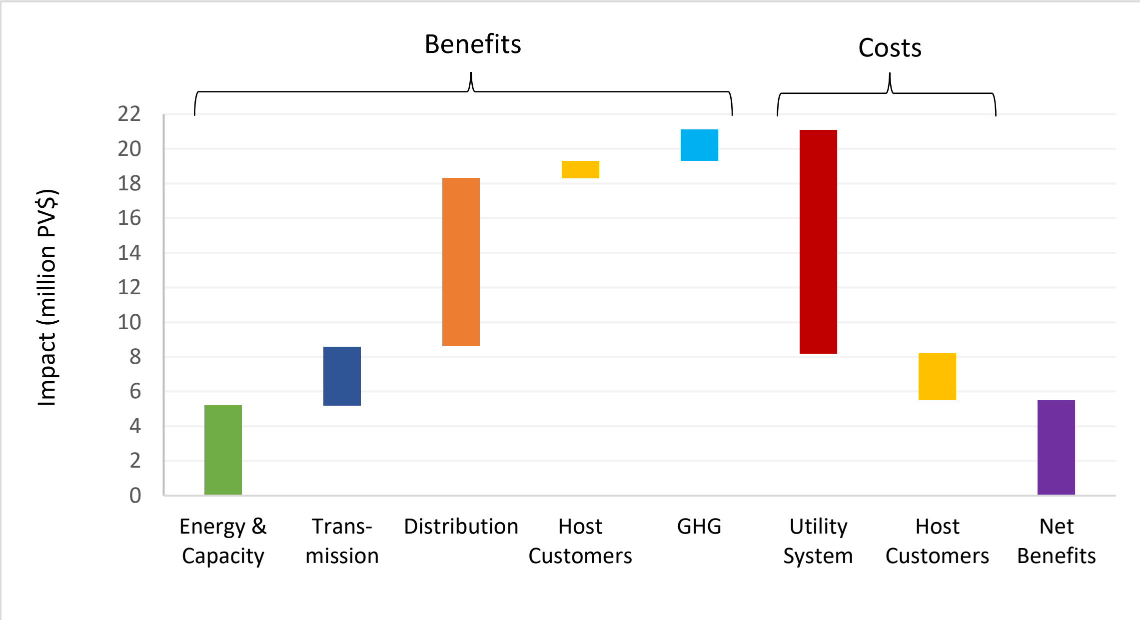
Table 12-3. Net Benefits and Costs of NWS Case Study: Societal Impacts

Type	Societal Impact	Cost or Benefit	Notes
Societal Impacts	GHG Emissions	●	GHG emissions reductions accrue as the NWS helps offset resources with higher marginal emission rates.
	Other Environmental	○	This example jurisdiction does not include these societal impacts in its JST based on its review of its applicable policies.
	Resilience	○	
	Economic and Jobs	○	
	Public Health	○	
	Low Income: Society	○	
	Energy Security	○	

● *= typically a benefit for this example;* ● *= typically a cost for this example;* ○ *= not relevant for this example.*

Figure 12-1 presents the utility system costs and benefits, low-income customer benefits, and GHG impacts, as required by this example jurisdiction's JST. As indicated, the T&D benefits represent a large portion of the benefits in this example, and this NWS initiative will result in net benefits.

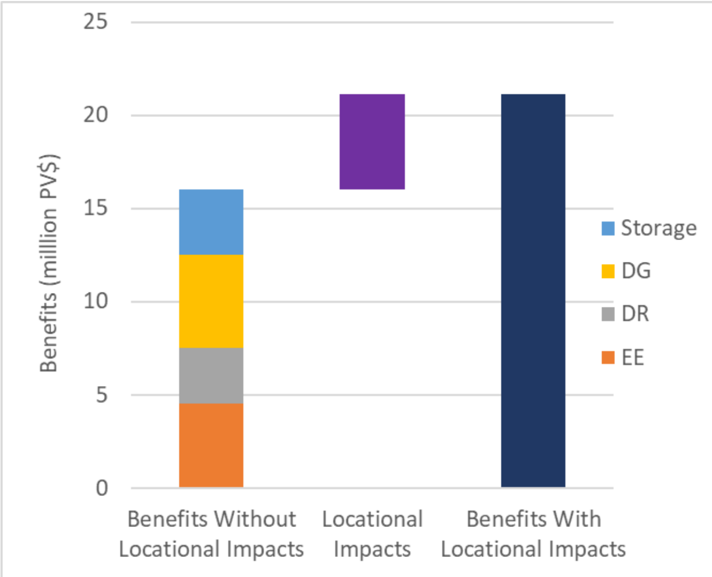
Figure 12-1. Example of NWS Cost-Effectiveness



In this case study, locational value plays a central role in the cost-effectiveness of an NWS, as represented by the significant T&D benefits in Figure 12-2. The assessment of NWS cost-effectiveness depends on where the DERs are located, when they provide services, and the resulting benefits and costs.

Figure 12-2 illustrates the effect that locational benefits of DERs can have on this hypothetical NWS. It presents (a) the benefits of each DER type without accounting for locational impacts (i.e., assuming system average T&D benefits); (b) the locational benefits associated with this NWS initiative; and (c) and the total benefits after accounting for locational impacts. The DR and distributed storage resources would be expected to have the greatest locational benefits because they can be operated at the times of distribution and transmission system peaks.

Figure 12-2. Example of NWS Locational Benefits



The text box below provides a real-world example of the dynamics of interactive effects. Additional information on NWSs can be found in E4TheFuture, PLMA, SEPA 2018.

EXAMPLE PROJECT: NATIONAL GRID – TIVERTON NWA PILOT

In 2012, National Grid launched the Tiverton NWA Pilot to defer a $2.9 million, six-year feeder project with expectations of cumulatively meeting a 1 MW goal. This project also sought to test whether geographically targeted EE and DR resources (including Wi-Fi thermostats, heat pump water heaters, and window air conditioners) could defer the needs for a new substation feeder upgrade serving 5,200 majority residential customers in two communities in Rhode Island. The proposed upgrade was necessary to address distribution grid constraints due to summer weather-induced peaking.

The Tiverton NWA Pilot deferred the $2.9 million feeder project over five years; however, the project was not able to fully realize the 1 MW summer load reduction goal. As noted below, the NWA pilot achieved an overall benefit-cost ratio of 1.40, with each year proving to be cost-effective (except for 2018, which was previously identified as the post-pilot final evaluation for related costs only). The benefit-cost calculations were calculated using the Total Resource Cost test.

The Tiverton NWS pilot example explores key factors and challenges discussed in the chapter above, including option value, load forecasts, and customer adoption. Due to slower than forecasted load growth, as well as cooler 2017 summer temperatures, the substation upgrade was deferred beyond the original date of 2017. National Grid continues to monitor loading on the feeder.

Summary of Cost-Effectiveness for the Tiverton NWS Pilot Project

System Reliability Procurement (SRP) - Tiverton/Little Compton

Summary of Cost Effectiveness ($000)

	2012	2013	2014	2015	2016	2017	2018	Overall
BENEFITS	**$179.0**	**$1,325.4**	**$1,033.3**	**$1,281.1**	**$687.7**	**$568.0**	**$0.0**	**$5,074.6**
Focused Energy Efficiency Benefits	$90.2	$1,015.1	$716.7	$1,024.8	$435.0	$66.94	$0.0	$3,348.7
SRP Energy Efficiency Benefits	$88.8	$310.4	$136.8	$78.0	$88.1	$341.6	$0.0	$1,043.7
Demand Reduction Benefits	$0.0	$0.0	$5.6	$6.8	$5.3	$11.3	$0.0	$28.9
Deferral Benefits	$0.0	$0.0	$174.2	$171.5	$171.5	$148.2	$0.0	$635.3
COSTS	**$133.4**	**$672.4**	**$569.3**	**$1,029.4**	**$611.1**	**$510.9**	**$90.8**	**$3,617.4**
Focused Energy Costs	$46.6	$331.1	$195.8	$529.3	$280.1	$281.3	$0.0	$1,664.1
System Reliability Procurement Costs	$86.8	$341.3	$373.5	$500.2	$331.0	$229.6	$90.8	$1,953.3
BENEFIT/COST RATIO	**1.34**	**1.97**	**1.81**	**1.24**	**1.13**	**1.11**	**-**	**1.40**

NOTES:

- Focused EE benefits include the NPV (over the life of these measures) of all TRC benefits associated with EE measures installed in that year that are being focused to the Tiverton/Little Compton area.
- SRP EE benefits include all TRC benefits associated with EE measures in each year that would have been installed as part of the statewide EE programs.
- DR benefits represent the energy and capacity benefits associated with the demand reduction events projected to occur in each year.
- Deferral benefits are the NPV benefits associated with deferring the wires project (substation upgrade) for a given year in $2014.
- EE costs include PP&A, Marketing, STAT, Incentives, Evaluation and Participant Costs associated with statewide levels of EE that have been focused to the Tiverton/Little Compton area. For the purposes of this analysis, they are derived from the planned ¢/Lifetime kWh in Attachment 5, Table E-5 of each year's EEPP in the SF EnergyWise and Small Business Direct Install program. These are the programs through which measures in the SRP pilot will be offered.
- SRP costs represent the SRPP budget which is separate from the statewide EEPP budget, as well as SRP participant costs. The SRP budget includes PP&A, Marketing, Incentives, STAT and Evaluation. All benefits and costs are in $current year except for the deferral benefits. 2012-2017 numbers have been updated to reflect year-end data. 2018 numbers reflect year-end projections.

Source: E4TheFuture, PLMA, SEPA 2018, based on data from National Grid (The Narragansett Electric Company), System Reliability Procurement 2019 Report, October 2018.

13. SYSTEM-WIDE DER PORTFOLIOS

This chapter provides guidance on how to analyze a portfolio of multiple DER types across a utility service territory, including guidance on how to prioritize across DERs.

13.1 Summary of Key Points

- In analyzing portfolios of multiple DER types, it is important to first establish a single primary cost-effectiveness test that can be used for all DER types.
- In analyzing portfolios of multiple DER types, it is important to account for interactive effects between multiple DER types, including enabling effects, savings effects, and avoided cost effects.
- In analyzing portfolios of multiple DER types, it is useful to articulate the jurisdiction's DER planning objectives, for example: implement all cost-effective DERs; implement the lowest-cost DERs; maximize capacity benefits from DERs; encourage a diverse range of DER technologies; encourage customer equity; achieve GHG or electrification goals at lowest cost; and avoid unreasonable rate impacts.
- In analyzing portfolios of multiple DER types, it can be useful to present the BCA results in ways that facilitate comparison across DER types. For example:
    - DERs can be ranked by benefit-cost ratios or net benefits to indicate the most cost-effective DERs.
    - Levelized DER costs can be used to directly and consistently compare costs across different DER types.
    - Levelized net cost curves can be used to compare and prioritize DERs according to key parameters such as $/ton GHG reduced.
    - Multiple cost-effectiveness tests, in addition to the JST, can be used to provide additional information when analyzing portfolios of multiple DER types.
- Any analysis of the rate impacts from portfolios of multiple DER types should assess the rate, bill, and participation impacts of all DER types in combination.

13.2 Introduction

Chapters 6 through 10 discuss how DER types can be assessed in isolation using *single-DER analysis*. This chapter refers to how to assess all DER types within a jurisdiction or service territory using *multiple-DER analysis*. Chapter 14 discusses how IDP can be used to optimize multiple DERs and supply-side resources.

A jurisdiction's primary cost-effectiveness test should be designed to answer the key question: *Which DERs have benefits that exceed costs and therefore merit utility funding or support on behalf of customers?* (See Chapter 3.) Once this universe of cost-effective DERs has been defined and identified, some jurisdictions may wish to address a secondary question: *Which of those cost-effective DERs should be funded or supported by a utility on behalf of customers?* This chapter provides guidance on how to address this second question.

When analyzing the cost-effectiveness of a portfolio of DERs across a utility service territory, it is helpful to begin by articulating the jurisdiction's DER planning objectives. This allows regulators, utilities, and others to identify the criteria that will be used to prioritize across different DER types.

13.3 Consistent Cost-Effectiveness Tests

When analyzing a portfolio of multiple DER types across a utility service territory, it is especially important to apply consistent cost-effectiveness principles, methodologies, and assumptions across all DER types. Otherwise, utilities risk over-investing in some DER types and under-investing in others, resulting in increased costs for utility customers and missed opportunities for achieving applicable policy goals.

The best way to ensure consistency across DER types is to use the same primary cost-effectiveness test for all types. A single primary test for all DERs can be developed using the NSPM BCA Framework following the same steps used to develop a primary test for a single DER type. (See Section 3.4.)

In some cases, STEP 1 of the NSPM BCA Framework—*Articulate Applicable Policy Goals*—may be challenging to apply where jurisdictions have different policy goals for different DER types. This can make it difficult to establish a single primary test for all DER types. In these instances, the primary DER test could be based on the narrowest set of policy goals, the broadest set of policy goals, or something in between. (See Section 3.5.3.)

If a jurisdiction is unable to develop a single primary test to evaluate to all DERs, secondary tests can help promote consistency across DERs. Several options are available for secondary tests. (See Section 3.5.3, Chapter 13, and Appendix D.)

13.4 Interactive Effects

Different DER types can have interactive effects on each other, including effects on avoided costs and effects on kWh or kW impacts, and enabling other DERs. These interactive effects should be accounted for when assessing the cost-effectiveness of initiatives that promote multiple DER types, if such impacts are determined to be material.

- *Marginal System Costs:* When a large number of DERs are installed in one region, they can affect the avoided costs of other DERs within that region. The best way to do account for this effect is through IDP (see Chapter 14). In the absence of IDP, different approaches can be used to approximate the interactive effects on avoided costs (see Section 5.4.1). In the case of multiple DER types across a service territory, the interactive effects on avoided costs could be significant, especially under high rates of DER deployment.
- *kWh and kW Effects:* When multiple DER types are deployed, the operation of one DER type might affect the kWh or kW impacts of other DER types. In the case of multiple DER types across a service territory, it is possible that the operation of one DER will affect the kWh or kW impacts of another type, especially in the case of distributed storage resources. In these cases, it will be important to estimate these interactive effects (see Section 5.4.2). Evaluation efforts for these initiatives should specifically investigate how different DER types affect the kWh and kW impacts of other DERs, so that better information will be available over time.

- *Enabling Effects:* Some DERs can make it easier or more cost-effective to adopt other types of DERs. In the case of multiple DER types across a service territory, it is unlikely that some DERs will help make other DERs more cost-effective. This effect is most likely to occur for multiple DERs per site or for NWS applications. If there are any enabling effects, however, they should be accounted for in the cost-effectiveness analysis (see Section 5.4.3).

13.5 DER Planning Objectives

13.5.1 DER Planning Objectives

When analyzing the cost-effectiveness of a portfolio of DERs across a utility service territory, it is helpful to begin by articulating the jurisdiction's DER planning objectives. This allows regulators, utilities, and others to identify the criteria that will be used to prioritize across different DER types.[53]

In general, a jurisdiction's policy goals should inform DER planning objectives. Planning objectives are different from policy goals, however, in that they give priority to certain goals. For example, two jurisdictions might have a policy goal of reducing GHG emissions, but one jurisdiction might decide to make decarbonization a planning objective while another one might not. The jurisdiction with decarbonization as a planning objective might choose to prioritize DERs on the basis of GHG reduction potential (for example, by considering levelized $/ton GHG reduced).

There are many DER objectives that jurisdictions could use for planning purposes. In those cases, it might be useful to revisit those planning objectives in light of evolving goals, new DER technologies and services, and other developments in the electricity and gas industries.

One DER planning objective would be to implement all cost-effective DERs. However, some regulators might be cautious about implementing all cost-effective DERs because of budget constraints, rate impacts, or other concerns. In these cases, alternative planning objectives can be used to design system-wide DER portfolios. Examples of potential planning objectives include:

- Implement the most cost-effective DERs.
- Encourage a diverse range of DER technologies.
- Encourage customer equity.
- Achieve GHG goals at lowest cost.
- Avoid unreasonable rate impacts.
- Achieve multiple planning objectives.

The following sections offer guidance on how to present and evaluate the BCA results in order to identify those DERs that best meet these planning objectives.

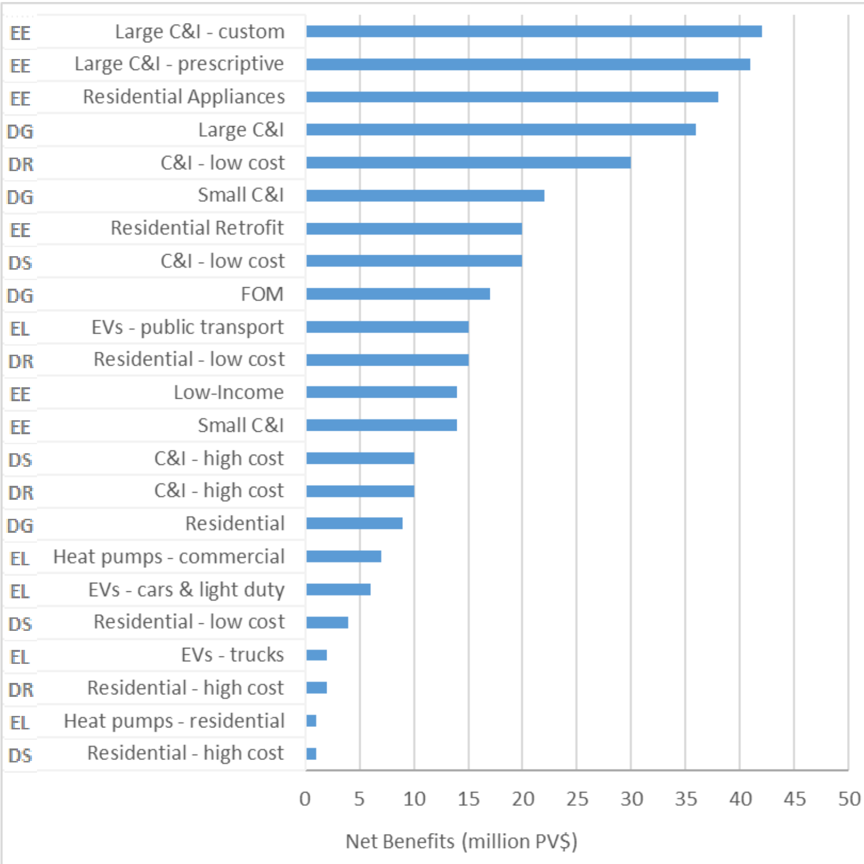
13.5.2 Objective: Implement the Most Cost-Effective DERs

Jurisdictions with a planning objective to implement the most cost-effective DERs can do so by maximizing either net benefits or benefit-cost ratios of the primary DER cost-effectiveness test for the

[53] In general, DER planning objectives should be consistent with the planning objectives applied to other utility resources.

jurisdiction. Figure 13-1 shows the cost-effectiveness results for a set of illustrative DERs, in terms of net benefits.[54]

Figure 13-1. Example DERs Sorted by Net Benefits



Source: Appendix D.

These results could be used to prioritize across DERs and select the most cost-effective ones. For example, utilities or others could accept the most cost-effective DERs, in terms of either net benefits or benefit-cost ratios, until a certain implementation budget cap is reached. As another example, utilities or others could accept the most cost-effective DERs, in terms of either net benefits or benefit-cost ratios, until a certain rate impact cap is reached.[55]

If net benefits are used to determine the most cost-effective DERs, then this will result in the largest amount of net benefits. If, instead, benefit-cost ratios are used to determine the most cost-effective

[54] The DERs and cost-effectiveness results presented in these figures 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. Further, some DER types are bundled together to keep the figures from being too complex. (See Appendix D.)

[55] After ranking the DER BCA results in this way, one might draw the conclusion that all of the most cost-effective DER (FOM DG in this example) should be acquired before beginning to acquire the next most cost-effective DER (large C&I in this example). However, this approach would undermine other DER planning objectives, such as encouraging customer equity and encouraging a diverse range of DER types and technologies. It would also run counter to conventional practices, which include acquiring multiple DER types in parallel.

DERs, then this will result in implementing those DERs that maximize the benefits for each dollar spent. There may be instances where the result is the same or similar.

13.5.3 Objective: Achieve GHG Goals at Lowest Cost

Jurisdictions with a planning objective to achieve GHG goals can do so by prioritizing the DERs that reduce GHG emissions at the lowest cost. This objective might be appropriate in jurisdictions that have clearly defined GHG reduction targets.

Net cost curves allow for a ranking of DERs according to what they cost to achieve a particular benefit (See Appendix D). A GHG net cost curve can be used to identify the lowest cost DERs available for reducing GHG emissions.[56]

Figure 13-2 presents an example GHG net cost curve for an illustrative set of DERs.[57] Net cost curves such as this are created with the following steps:

- Each DER's costs are put into levelized terms. Levelized costs include (a) the costs of the DER over its economic operating life, amortized over that lifetime and discounted back to the first year, divided by (b) the total lifetime energy produced.
- Each DER's benefits are also put into levelized terms. For the purpose of making a GHG cost curve, the GHG benefits are excluded from these levelized benefits. This allows for the presentation of net levelized costs required to achieve those GHG benefits (in $/ton GHG).
- The net levelized cost is determined by subtracting the levelized costs from the levelized benefits.
- The DERs are ordered from lowest net levelized cost to highest.
- The vertical axis presents the net levelized cost of each DER (in $/ton GHG).
- The horizontal axis presents the amount of GHG savings (in tons GHG) from each DER.

Appendix D describes levelized costs, the uses and limitations of cost curves, and the illustrative DERs used to create this figure.

The DERs whose net costs are negative in Figure 13-2 represent those DERs that are cost-effective without accounting for GHG emissions. The DERs whose net costs are positive represent those that are not cost-effective without accounting for GHG emissions, but that might be after accounting for these emissions.

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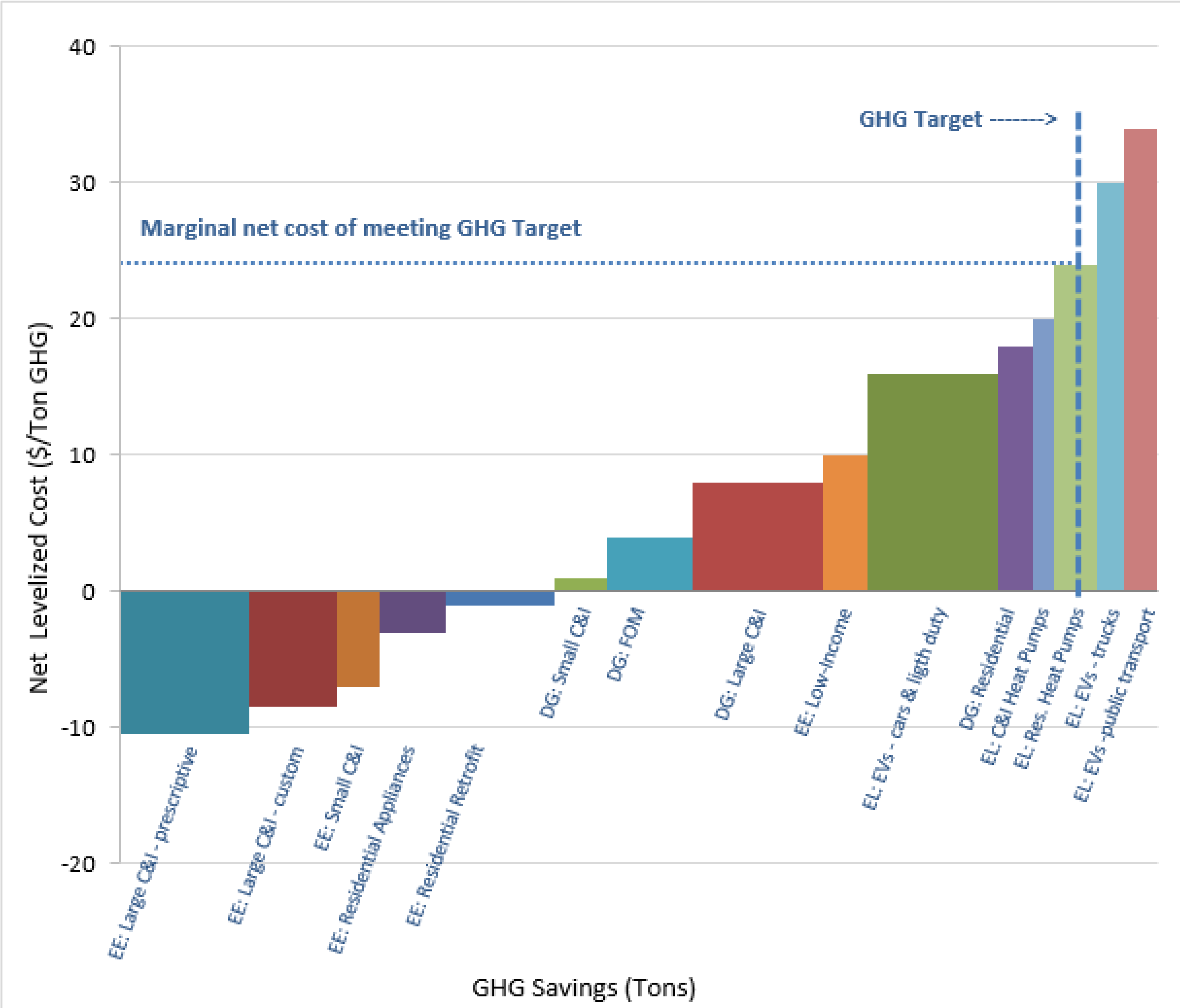
[56] For a useful example of levelized net cost curves, see McKinsey 2013.

[57] 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. Further, some DER types are bundled together to keep the figures from being too complex. (See Appendix D.)

Figure 13-2. GHG Reduction Net Cost Curve



Source: These are hypothetical examples. All data used here are discussed further in Appendix D.

Net cost curves such as this one can be used for several purposes. For example:

- They can be used to prioritize DERs according to those that will reduce GHG emissions at the lowest cost. The leftmost DERs can be prioritized over those on the right.
- They can be used to determine which are the lowest-cost DERs available to meet a particular GHG target. Figure 13-2 includes a dashed vertical line indicating the relevant GHG target for this hypothetical jurisdiction. The DERs to the left of that line represent the lowest cost options for meeting this GHG target.
- They can be used to identify the marginal net cost of complying with a specific target. Figure 13-2 includes a dotted horizontal line that indicates the marginal resource needed to meet the relevant GHG target for this hypothetical jurisdiction. In this example, the marginal resource is EV initiatives for public transportation. As indicated in the previous figure, the cost of this DER is roughly 80 $/ton GHG. This marginal cost could be used as an input to the BCA, where the value in $/tons is used as the cost of achieving the jurisdiction's GHG target.

13.5.4 Objective: Encourage Customer Equity

Jurisdictions with a planning objective to encourage customer equity can do so by giving priority to those DERs that reach a broad range of customers, serve multiple customer types, or serve otherwise hard-to-reach customers.

Examples of DERs that might be prioritized over others in order to promote customer equity include:

- Low-income EE programs that might be less cost-effective than other DERs but provide important equity benefits to low-income customers.
- DR programs for residential customers to be consistent with similar programs for commercial and industrial customers, even if the former costs more than the latter.
- DPV initiatives such as community solar projects that allow customers to enjoy the benefits of DPV even if they do not own or occupy a building that can support DPV technologies. Such initiatives could also be designed to serve low-income or other underserved customers.
- Locating EV chargers in economically distressed areas or in public places that are not well-served by privately funded EV chargers.

13.5.5 Objective: Encourage a Diverse Range of DERs

Some regulators and others might prefer to encourage a diverse range of DER types based on the logic that all DER types deserve some utility support because they all contribute benefits in different ways and there is value in promoting a diversity of technologies. Diversity across technologies can also help reduce system risk.

In this case, regulators might decide to support a minimum amount of each type of DER. This could be achieved by sorting the DER types by net benefits or benefit-cost ratios, as indicated in Figure 13-1, and selecting the lowest cost options for each type of DER. This might result in utilities implementing some DER types that are less cost-effective than other DER types that are not implemented.

Table 13-1 presents one example of how such a portfolio might be developed. It presents five DER types and several DERs within each type.[58] The DERs are sorted by type, and for each DER type the results are sorted by benefit-cost ratios. In this hypothetical jurisdiction, the planning objective is to support the most cost-effective DERs while encouraging a range of DER technologies. This DER portfolio is designed to include those DERs that have a benefit-cost ratio of 1.6 or greater or are needed to support DER technology diversity.[59] As indicated with green shading in Table 13-1, several DERs are included in the portfolio because they support technology diversity, despite having benefit-cost ratios less than the planning threshold.

[58] The DERs and cost-effectiveness results presented in these figures 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. Further, some DER types are bundled together to keep the figures from being too complex. (See Appendix D.)

[59] This cost-effectiveness “floor” was chosen simply to illustrate one way to prioritize DERs.

Table 13-1. Example DER Portfolio Developed to Encourage a Diverse Range of Technologies

DER Type	DER	Net Benefits (million PV$)	BCR	Reason for Including or Excluding
DG	Large C&I	36	1.9	Include: BCR high
DG	FOM	17	1.7	Include: BCR high
DG	Small C&I	22	1.7	Include: BCR high
DG	Residential	12	1.5	Include: needed for diversity
DR	C&I - low cost	30	1.6	Include: BCR high
DR	Residential - low cost	15	1.5	Include: needed for diversity
DR	C&I - high cost	10	1.3	Exclude: BCR low, not needed for diversity
DR	Residential - high cost	2	1.1	Exclude: BCR low, not needed for diversity
Storage	C&I - low cost	20	1.5	Include: needed for diversity
Storage	C&I - high cost	10	1.3	Exclude: BCR low, not needed for diversity
Storage	Residential - low cost	4	1.2	Include: needed for diversity
Storage	Residential - high cost	1	1.1	Exclude: BCR low, not needed for diversity
EE	Large C&I - prescriptive	41	2.2	Include: BCR high
EE	Large C&I - custom	42	2.1	Include: BCR high
EE	Residential Appliances	38	1.8	Include: BCR high
EE	Low-Income	14	1.6	Include: BCR high
EE	Residential Retrofit	20	1.5	Include: needed for diversity
EE	Small C&I	14	1.3	Include: needed for diversity
Electrification	C&I Heat Pumps	7	1.7	Include: BCR high
Electrification	EVs - public transport	15	1.5	Include: needed for diversity
Electrification	EVs - trucks	2	1.4	Exclude: BCR low, not needed for diversity
Electrification	EVs - cars & light duty	6	1.2	Include: needed for diversity
Electrification	Res. Heat Pumps	1	1.1	Include: needed for diversity

Source: These are hypothetical examples (see Appendix D).

13.5.6 Objective: Avoid Unreasonable Rate Impacts

Jurisdictions that want to avoid unreasonable rate impacts could do so by conducting rate, bill, and participation analyses to supplement the cost-effectiveness analyses (See Section 2.3 and Appendix A).

In this context, it is useful to conduct a rate, bill, and participation analyses on different DER portfolios to see whether the combined rate impacts of all DER types are reasonable. If rate impacts are estimated to be unreasonably high under one scenario, then other scenarios can be developed to either include more DERs that reduce rates, fewer DERs that increase rates, or both.

Figure 13-3 provides an example of a useful way to present the results of a long-term rate impact analysis.[60] This example shows the estimated long-term rate impacts, in terms of percent changes in rates, for six different DER types. It also shows the long-term rate impacts of all the DERs combined. In

[60] The DERs and results presented in this figure are purely illustrative and not based on specific DERs in a specific jurisdiction. Actual results could be significantly different from those presented here. Further, results will vary within the DER types presented here; the DER types are bundled together to keep the figures from being too busy. (See Appendix A.)

this example, the long-term rate increases from EE and DG resources are essentially offset by the rate reductions from the other DER types.

Figure 13-3. Example Presentation of Long-Term Rate Impacts

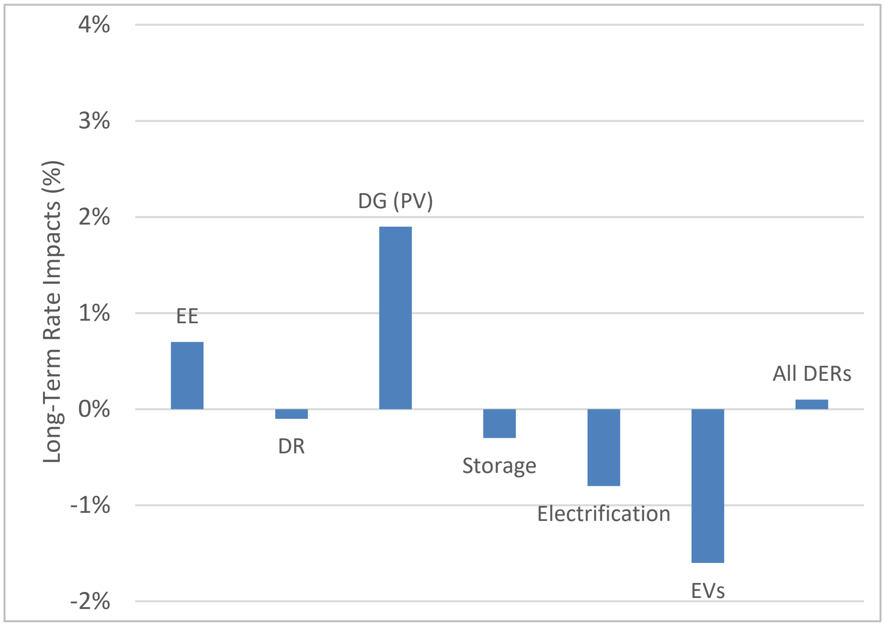


Figure 13-4 provides an example of a useful way to present the results of a long-term bill impact analysis.[61] This analysis includes the average bills across all utility customers, including both DER host customers and other customers. Also, for those resources that affect multiple fuel types, such as electrification and EVs, this analysis reflects the impact on the combined bills for all the fuels affected by the DER.

61 See Footnote 63.

Figure 13-4. Example Presentation of Long-Term Average Combined Bill Impacts

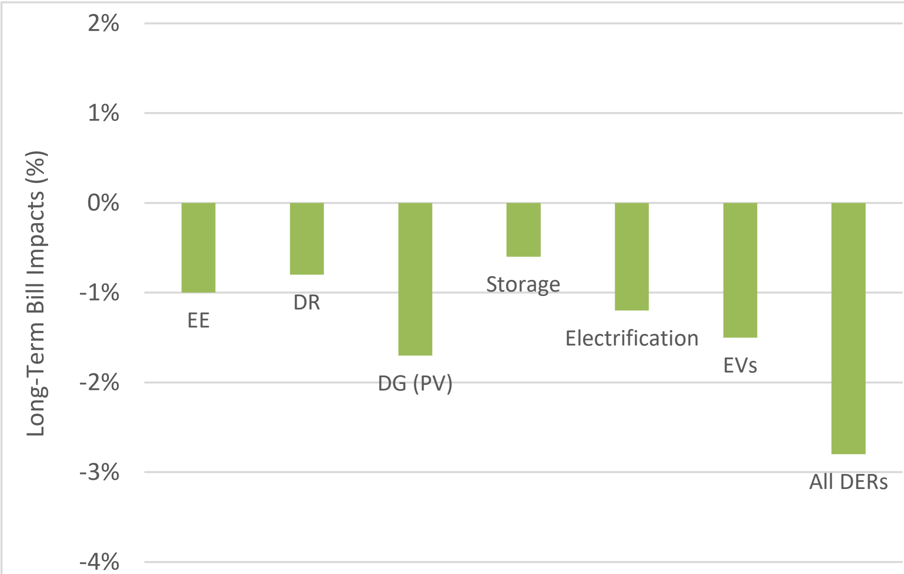
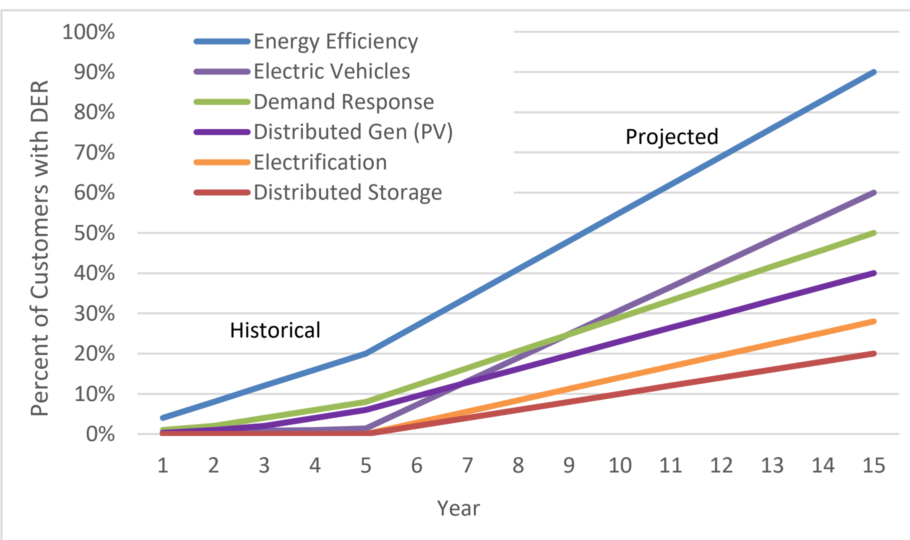


Figure 13-5 provides an example of a useful way to present the results of a long-term participation analysis.[62] It presents five years of historical DER participation rates, as well as 10 years of projections of future participation rates. Participation rates present the number of participants in a program divided by the total eligible participants. Ideally, the participation rates would account for customers who participate in more than one program or install more than one type of DER. That would allow for the presentation of the percentage of DER host versus non-host customers, which would help inform discussions about customer equity.

Figure 13-5. Example Presentation of Long-Term Participation Impacts



[62] The DERs and results presented in this figure are purely illustrative and not based on specific DERs in a specific jurisdiction. Actual results could be significantly different from those presented here. Further, results will vary within the DER types presented here; the DER types are bundled together to keep the figures from being too busy. (See Appendix A.)

13.5.7 Multiple Planning Objectives

Many jurisdictions are likely to have multiple DER planning objectives. In these cases, regulators can establish a set of criteria to use in designing the preferred DER portfolio. For example, a jurisdiction might have the following set of planning criteria:

- Every DER portfolio must, at a minimum, meet statutory targets for specific DER types.
- The preferred DER portfolio should encourage customer equity by giving priority to DERs that serve a broad range of customers, provide balance across customer types, and serve otherwise hard-to-reach customers.
- The preferred DER portfolio should seek to encourage technology diversity by including at least a minimum amount of support for each type of DER.
- The preferred DER portfolio should result in reasonable long-term average rate impacts, commensurate with the benefits provided by the DERs and the customer participation in DERs.
- The preferred DER portfolio should be designed to meet the jurisdiction's GHG goals.

With planning criteria such as these in place, utilities and others can then investigate different combinations of DERs with the goal of meeting the criteria as much as possible.

Table 13-2 provides an example of a DER portfolio developed using multiple planning objectives to determine which DERs should be funded or otherwise supported by utilities. The DERs are sorted from high to low benefit-cost ratios. The top 10 DERs are included in the portfolio because they have high net benefits and benefit-cost ratios. Other DERs are included in the portfolio because they are cost-effective, and they help meet other planning objectives. Three DER were not included in the portfolio even though they are cost-effective, because they had low benefit-cost ratios and were not needed to meet planning objectives.

Table 13-2. Example DER Portfolio Developed Using Multiple Planning Objectives

DER Type	DER	Net Benefits (million PV$)	BCR	Reason for Including
EE	Large C&I - prescriptive	41	2.2	High BCR & net benefits
EE	Large C&I - custom	42	2.1	High BCR & net benefits
DG	Large C&I	36	1.9	High BCR & net benefits
EE	Residential Appliances	38	1.8	High BCR & net benefits
DG	Small C&I	22	1.7	High BCR & net benefits
Electrification	Heat pumps - commercial	7	1.7	High BCR & net benefits
DG	FOM	17	1.7	High BCR & net benefits
EE	Low-Income	14	1.6	High BCR & net benefits
DR	C&I - low cost	30	1.6	High BCR & net benefits
DR	Residential - low cost	15	1.5	High BCR & net benefits
Electrification	EVs - public transport	15	1.5	High BCR & net benefits
Storage	C&I - low cost	20	1.5	High BCR & net benefits
EE	Residential Retrofit	20	1.5	High BCR & net benefits
DG	Residential	9	1.5	High BCR & net benefits
Electrification	EVs - trucks	2	1.4	Needed to meet GHG target
EE	Small C&I	14	1.3	Customer equity
Storage	C&I - high cost	10	1.3	Exclude from portfolio
DR	C&I - high cost	10	1.3	Exclude from portfolio
Storage	Residential - low cost	4	1.2	Technology diversity & customer equity
Electrification	EVs - cars & light duty	6	1.2	Needed to meet GHG target
Storage	Residential - high cost	1	1.1	Exclude from portfolio
DR	Residential - high cost	2	1.1	Exclude from portfolio
Electrification	Heat pumps - residential	1	1.1	Needed to meet GHG target

Source: These are hypothetical examples (see Appendix D).

13.5.8 Testing the Planning Objectives

It can be useful to test the implications of a jurisdiction's planning objectives by considering the key results of the BCA alongside the key results of the rate, bill, and participation analysis. Regulators, utilities, and others can review these key results to assess tradeoffs between cost-effectiveness and customer equity.

Table 13-3 presents an example comparison of the key results of several DER portfolios developed with different planning objectives. It shows the results of the BCA (in terms of benefit-cost ratios and net benefits), as well as the results of the rate, bill, and participation analysis. The table presents five scenarios: (1) including all cost-effective DERs; (2) focusing on multiple planning objectives; (3) focusing on diverse DER technologies; (4) focusing on the most cost-effective DERs due to budget constraints; and (5) focusing on a mix of DERs that minimizes negative rate impacts.

Table 13-3. Example DER Portfolios Developed Using Different Planning Objectives

Planning Objective	Benefit-Cost Ratio	Net Benefits (million PV$)	Rate Impact	Average Bill Impact	Participation Rates
1. All Cost-Effective DERs	1.5	376	0.6%	-2.6%	28%
2. Multiple Planning Objectives	1.7	353	0.8%	-2.3%	26%
3. Encourage Diverse Technologies	1.8	348	0.9%	-2.4%	21%
4. Most Cost-Effective DERs	2.2	320	0.5%	-2.0%	19%
5. Minimize Negative Rate Impacts	1.9	290	0.2%	-1.8%	16%

Source: These are hypothetical examples (see Appendix D).

Regarding the key results across scenarios:

- Benefit-cost ratios will typically increase as some of the less cost-effective DERs are removed from the portfolio.
- Net benefits will typically decline as some of the less cost-effective DERs are removed from the portfolio.
- The change in rate impacts will depend upon which DERs are included in the portfolio. The direction and magnitude of rate impacts will vary by DER.
- Average bill impacts will typically decline as DERs are removed from the portfolio. All DERs whose utility system benefits exceed utility system costs will reduce average bills.
- The participation rates will decline as DERs are removed from the portfolio. All else being equal, fewer DERs will result in fewer participants.

Regarding the key results for each scenario:

1. *All Cost-Effective DERs:* The benefit-cost ratio is the lowest, but the net benefits are the highest. The participation rate is also the highest because this scenario includes the greatest number of DERs.
2. *Multiple Planning Objectives:* The rate impacts are higher than those for the All Cost-Effective DERs scenario because the DERs that were removed for this scenario were DG and storage DERs that have downward pressure on rates.
3. *Encourage Diverse Technologies:* The rate impacts are highest because the DERs that were removed for this scenario were DG and storage—DERs that have downward pressure on rates.
4. *Most-Cost-Effective DERs:* The benefit-cost ratio is the highest, but this scenario has relatively low net benefits and participants.
5. *Minimize Negative Rate Impacts:* The rate impacts are the lowest of all scenarios, but the participation rates are also the lowest. This illustrates the tradeoff between minimizing rate impacts and increasing participation rates, both of which affect customer equity.

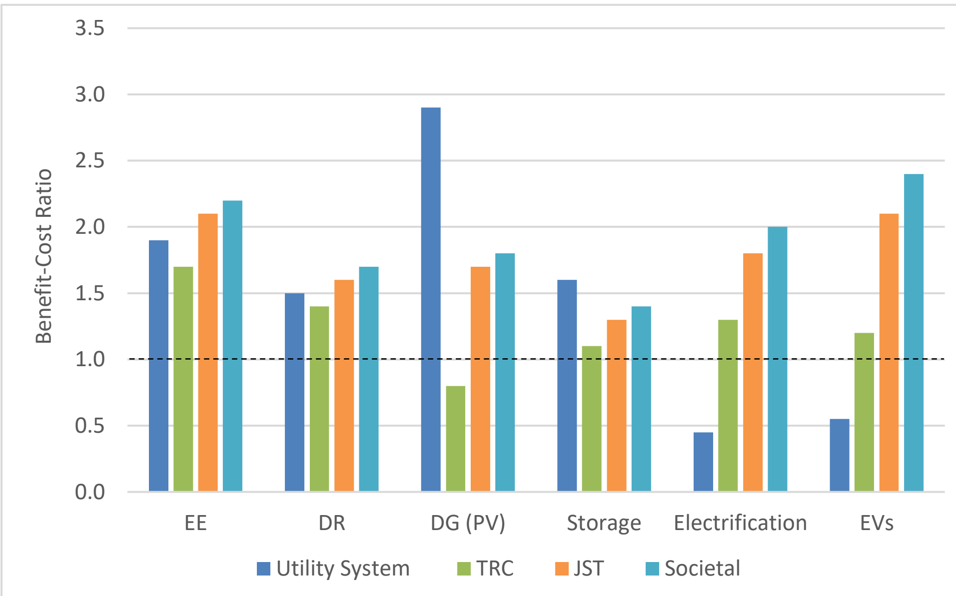
This sort of portfolio analysis can help regulators, utilities, and other stakeholders assess the implications of their planning objectives. The results presented in Table 13-3 are illustrative. Actual results will depend upon multiple factors and could vary significantly from those presented here both in direction and magnitude.

13.6 Multiple Tests

In some instances, multiple tests can be helpful when developing portfolios of multiple DER types. Different tests provide different information, and there may be situations where that additional information is helpful in understanding, prioritizing, and deciding among DER options.

Figure 13-6 presents an illustrative example for how to present the results of multiple tests for multiple DER types. It includes benefit-cost ratios for five DER types according to three traditional tests and a JST. The dashed line indicates the benefit-cost ratio of one, which is the threshold above which DERs are cost-effective. Presenting the results this way allows for a quick assessment of how cost-effective the different DER types are according to different tests.

Figure 13-6. Presentation of Multiple BCA Tests: Benefit-Cost Ratios, Multiple DER Types



Source: These are hypothetical examples. All data used here are discussed further in Appendix D.

This example uses a hypothetical JST that includes the following impacts: utility system, host customer, other fuel, low-income, and GHG emissions.

13.7 Rate Impacts of DER Portfolios

Rate impact analyses should be conducted separately from cost-effectiveness analyses. Rate impacts and cost-effectiveness are two separate issues and analyzing them separately provides much more meaningful information than combining them in a single analysis. (See Chapter 2 and Appendix A.)

The potential rate impacts of programs offering multiple DER portfolios will depend on many factors, including the choice of DERs deployed; the magnitude of DER savings, generation, and consumption; the DER deployment; the DER utility system costs; and the utility system avoided costs.

Rate impact analyses of portfolios with multiple DER types should assess the rate, bill, and participation impacts of all DER types in combination. This offers the advantage of seeing how rate impacts of one DER type might offset, or exacerbate, the rate impacts of other DER types. (See Part III, Chapters 6–10 for further information on individual technology rate impacts, and Appendix A for additional information on rate impacts.)

14. DYNAMIC SYSTEM PLANNING

Dynamic planning practices allow utilities to more dynamically optimize DERs and maximize their value to the system. These types of dynamic planning processes—referred to as integrated distribution planning (IDP) for distribution-level planning only and integrated grid planning (IGP) for full-system planning—are complex, and best practices are still evolving. This chapter provides a brief overview of the key concepts associated with these emerging planning practices.

14.1 Summary of Key Points

- The scope of utility system planning is expanding to manage the increasing complexity of the electricity system, while addressing evolving state policy objectives, changing customer priorities, and increased DER deployment.
- IDP can enable utilities to proactively plan the distribution system in a more dynamic way that better reflects the benefits and costs of DERs. To capture the full value potential of DERs, utilities require enhanced analytical capabilities.
- IGP requires alignment of the objectives, assumptions, and planning horizons between IDP, resource planning, and transmission planning.
- New planning components such as more granular forecasts, improved interconnection procedures, hosting capacity analysis, and locational value assessment can enhance traditional planning by informing a more comprehensive framework capable of addressing the full range of DER value to the grid. These enhanced practices can help identify values for otherwise hard-to-quantify impacts.
- Each of these types of planning practices uses some form of BCA for comparing and optimizing different resources.

14.2 Introduction

Chapters 6 through 10 discuss how different DERs can be assessed in isolation using *single-DER analysis*. Chapters 11 through 13 discuss how *multiple-DER analysis* can be used to assess DERs relative to a static set of alternative resources. This chapter discusses advanced planning practices that can allow utilities to more effectively and dynamically optimize DERs using *dynamic system planning*. These practices are complex and best practices are evolving.

Table 14-1 summarizes several different types of planning practices used by electric and gas utilities.[63] It presents practices according to whether they are used by distribution-only or vertically integrated utilities, and it shows which elements of the utility system are accounted for by each type of practice.

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[63] Jurisdictions have adopted a range of terms to describe planning processes. This manual uses the term "IDP" to describe enhanced distribution planning processes that dynamically optimize DERs and uses the term "IGP" to describe enhanced full-system planning processes that incorporate generation, transmission, and distribution, including DERs.

Table 14-1. Types of Planning Practices

Type of Utility System	Planning Practice	Planning Practice Accounts for: Distribution System	DERs	Transmission System	Utility-Scale Generation
Distribution-only & vertically integrated	Traditional distribution planning	✓	-	-	-
	Integrated distribution planning (IDP)	✓	✓	-	-
Vertically integrated	Transmission planning	-	-	✓	-
	Integrated resource planning (IRP)	-	✓	-	✓
	Integrated grid planning (IGP)	✓	✓	✓	✓

Utilities of all types have conducted traditional distribution system planning for many years to determine how to best build and maintain the distribution grid. The focus of this practice has been on providing safe, reliable power through the distribution grid at a low cost. It typically has not accounted for DERs as alternatives to traditional distribution system technologies.

IDP has recently evolved as a more comprehensive way for distribution-only utilities to incorporate DERs into traditional distribution system planning. It allows for evaluation of both traditional distribution resources and DERs for meeting distribution grid needs (ICF 2016).

Integrated resource planning (IRP) has been practiced for many years by vertically integrated utilities. It focuses on meeting forecasted peak and energy demands through a combination of DERs and utility-scale generation over a long-term planning period. IRP allows for the optimization of both utility-scale resources and DERs for meeting bulk system needs, but historically it has not been used to investigate how DERs can be used to optimize distribution system costs (RAP 2013c).

IGP has recently evolved as a more comprehensive way for vertically integrated utilities to incorporate DERs into traditional IRP practices. IGP allows for evaluation of all resource types (DERs and utility-scale supply-side resources) to enable optimization across all levels of the utility system (generation, transmission, and distribution) (HECO 2018).

This chapter focusses on IDP and IGP practices because these are evolving practices to better account for opportunities from DERs. In addition to expanding scope beyond traditional practices, IDP and IGP practices account for new priorities such as grid flexibility, resilience, decarbonization, and optimizing grid services. Some jurisdictions are increasingly requiring utilities to go beyond analyzing the impact of DERs on their system to further study how DERs can be optimized and integrated to provide a variety of services on the grid.

Many states are also increasingly interested in grid modernization planning. This practice is similar to traditional distribution planning and IDP, but also incorporates a variety of traditional and emerging utility-facing distribution technologies that can expand grid capabilities, reduce some distribution costs, and enable increasing levels of DER integration (EPRI 2015). For example, as part of the DOE's vision for Next Generation Distribution System platform (DSPx), distribution utilities would make investments in grid modernization technologies in order to more effectively integrate and utilize DERs (DOE 2017a).

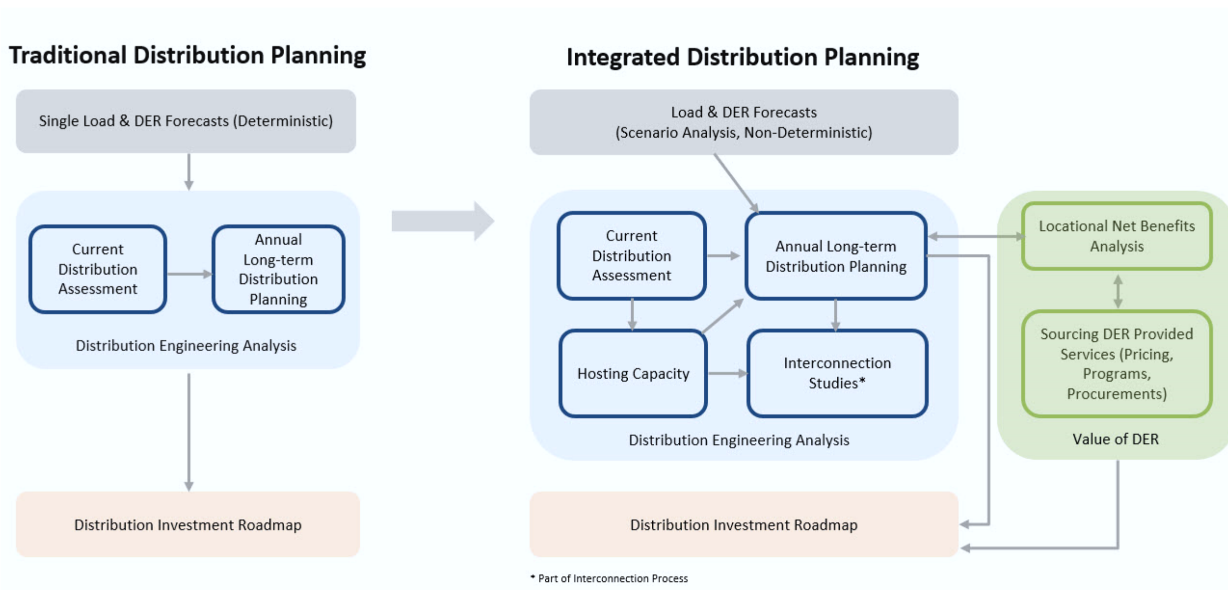
Grid modernization planning includes BCA as one component of the decision-making process, but it also includes a least-cost, best-fit component to address some decisions where BCAs are not feasible or warranted (DOE 2017a).[64] More detailed discussion of grid modernization planning is beyond the scope of this manual.

14.3 Integrated Distribution Planning

Traditional distribution planning is squarely focused on the engineering analysis required to identify needs on the distribution system and typically involves three steps: (1) develop a single load and DER forecast; (2) conduct distribution engineering analyses to assess the current distribution system and determine long-term needs; and (3) finalize a distribution investment roadmap.

As shown in Figure 14-1, IDP represents a significant enhancement over traditional planning and incorporates new elements and practices that result in a more holistic planning process. For example, instead of using a traditional, single deterministic load and DER forecast, IDP uses multiple scenario-based forecasts. Separately, the distribution engineering analysis is expanded to include elements of hosting capacity and interconnection studies, the latter of which overlaps with the utility interconnection process. The process also incorporates additional steps to assess DER value, including analysis of location-specific DER value and consideration of different DER sourcing mechanisms.

Figure 14-1. Comparison of Traditional Distribution Planning to Integrated Distribution Planning



Source: ICF 2016.

The following summarizes the core components of IDP:

- *Load and DER Forecasting:* Forecasting is evolving so that utilities are better able to identify system needs and address uncertainties about DER adoption and operation. Accounting for DER in load forecasts, increasing spatial and temporal granularity, and introducing probabilistic and

64 The least-cost, best fit approach is sometimes applied to utility projects where a utility has already made the decision that it needs to make an investment to meet a particular need, and the only remaining question is which technology will be the best fit at the lowest cost. A key difference between least-cost, best-fit and BCA approaches is that the former does not require an assessment of the benefits of the project because the need has already been established (DOE 2017a.)

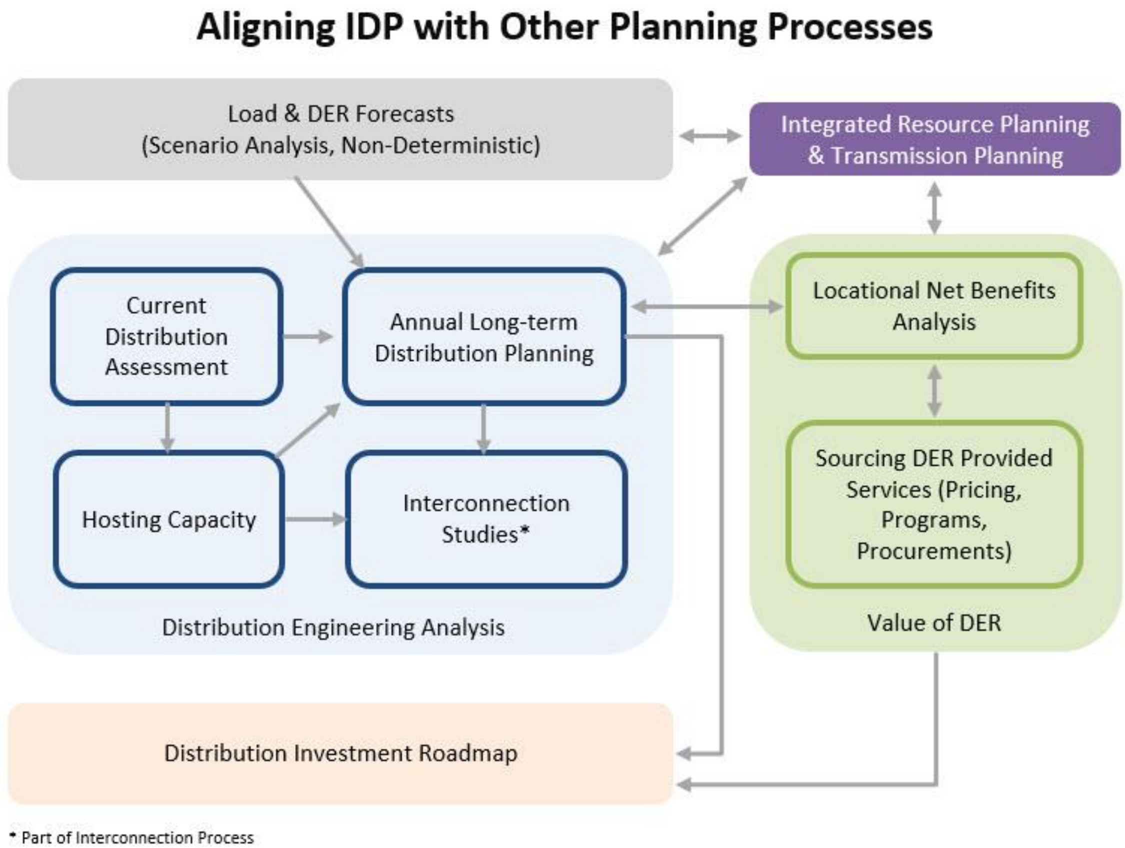
scenario planning help to better reflect DER impacts in forecasting and support more informed grid investments.

- *Hosting Capacity Analysis:* Hosting capacity is the amount of DERs that the distribution system can accommodate without adversely impacting power quality or reliability under current configurations and without requiring infrastructure upgrades. Hosting capacity analysis aims to enable greater DER integration by providing an improved understanding of constraints on the system and identifying where upgrades may be needed to support higher DER levels.
- *Interconnection:* System planners recognize the need to improve the efficiency and transparency of DER interconnection procedures to manage the workflow associated with a growing number of interconnection applications and meet customer expectations.
- *Locational Net Benefits Analysis:* The ability to measure and map the location of DER performance against utility planning criteria is a key benefit of assessing locational value in distribution planning. It enables the use of DERs to eliminate or defer system upgrades through NWSs and can inform other efforts including program design and more accurate pricing signals.
- *Sourcing DER-Provided Services:* Utilities can source services from DERs through a combination of mechanisms including programs, procurement, and pricing. Locational value assessments can inform the design of programs, where utilities provide targeted incentives to resources that deliver needed services. Other sourcing mechanisms, such as setting price signals for DER services through retail rates (time-varying rates, tariffs, etc.) or soliciting DER services through competitive procurements can also be developed to accurately and transparently reflect the temporal and locational value of DERs.

14.4 Integrated Grid Planning

Part of the progression beyond IDP is to move toward greater alignment with IRP and transmission planning to enable fully integrated system planning (see Figure 14-2, purple box). It becomes increasingly important to achieve this alignment with higher levels of DER deployment and greater provision of generation and transmission services from DERs. Comprehensive planning that accounts for these interactions enables consideration of DER to meet needs at all levels of the system.

Figure 14-2. Integrated Grid Planning: Expanding IDP to Include IRP and Transmission Planning



Source: ICF 2016.

To achieve the full value potential of DERs, utilities need to both advance their planning processes (i.e. IDP and full-system planning) and enhance operational capabilities. Without the requisite operational capabilities, utilities will be unable to account for and optimize the DER value that is otherwise identified through the planning process. As such, utilities need to enhance DER visibility (i.e. sensing and measurement) and control capabilities to effectively manage an increasingly complex and dynamic distribution system with higher DER deployment. By enabling DER value realization at the distribution level, it should by extension also unlock DER value potential at all levels of the system as IGP becomes more effectively integrated into whole-system planning processes.

14.5 BCA Issues and Challenges

There are a number of challenges to reaching fully integrated planning. An expanding set of planning objectives—such as clean energy, resilience, flexibility, equity and affordability, and more—widens the scope of planning activities and requires new methods, criteria, and models.

These additional objectives, combined with the increasing complexity of the electricity system, leads to the need for more sophisticated analytical tools and advanced modeling capabilities. The collection of more granular data is needed to support advanced analysis, but it requires consideration of protecting system security and customer privacy. Increased coordination and new information exchanges are needed within the utility, between the utility and other agencies with planning responsibility, and with stakeholders through increased transparency at critical steps in the planning process.

To address these challenges, regulators, utilities, and other stakeholders can:

- Work collaboratively to gain an understanding of the engineering analysis that is central to distribution planning. They can expand from there to incorporate advanced methods (e.g., hosting capacity analysis, non-wires alternatives, locational value, etc.) and common assumptions that support alignment and optimization across the system.
- Leverage pilots and demonstration projects to build operational experience and test new concepts, including new DER sourcing methods (e.g., competitive procurements, pricing strategies, and program design) that accurately communicate DER value to the system.
- Phase implementation of new elements and analytical capabilities in a "walk, jog, run" manner that allows for a gradual increase in the complexity of planning practices in accordance with desired objectives. They can also prepare for planning enhancements to occur in lockstep with broader evolution of the distribution system and culminate in a final stage characterized by active grid optimization.
- Eventually, work to identify the objectives, process steps, and timing cycles of distribution, transmission, and generation planning and seek consistency across these planning functions to allow for a fully integrated whole-system planning process.

To learn more about evolving electricity planning processes, NARUC and NASEO created a Joint Task Force on Comprehensive Electricity System Planning. The initiative offers resources to help states explore key topic areas related to aligned planning (NARUC, NASEO 2020). For specific information about how utility commissions can oversee the development of IDPs, see the Mid-Atlantic Distributed Resources Initiative (MADRI) white paper on "Integrated Distribution Planning for Electric Utilities: Guidance for Public Utility Commissions" (MADRI 2019).

Appendix A. Rate Impacts

This appendix explains how DERs can lead to rate impacts, and how rate impacts are different from cost-effectiveness and why the two should be examined using separate analyses. It also describes how to conduct a meaningful rate, bill, and participation impact analysis.

A.1 The Cause of Rate Impacts

DERs, like all utility resources, will impact customer rates. Some DERs are likely to increase rates, while other DERs are likely to reduce rates. Some may have very little effect on rates at all. The extent to which DERs will impact rates depends upon many factors, including the extent to which they reduce or increase utility system costs and the extent to which they reduce or increase utility sales.

In general, electricity and gas utility rates are set to equal utility system costs (i.e., revenue requirements) divided by sales (i.e., billing determinants). Therefore, analyzing DER rate impacts requires determining how DERs affect utility system costs and utility sales.

The extent to which DERs will create rate impacts typically depends upon several key factors:

- *Increases in utility system costs* will put upward pressure on rates. These might include, for example: program administration costs; financial incentives to developers and customers; and performance incentives. (See Table 4-1.)
- *Reductions in utility system costs* will put downward pressure on rates. These might include, for example: avoided energy costs, avoided generation capacity costs; avoided environmental compliance costs; avoided RPS/CES compliance costs; market price suppression effects; avoided transmission costs; and avoided distribution costs. (See Table 4-1.)
- *Reductions in sales* from DER resources will put upward pressure on rates. Reduced sales lead to lost revenues which might require increased rates in order to recover fixed costs over fewer sales.[65]
- *Increases in sales* from DER resources will put downward pressure on rates. Increased sales lead to increased revenues, which might allow rates to be reduced because the increased revenues can help pay for fixed costs over more sales.
- *Rate design* will affect the amount of lost or increased revenues created by the DER. Fixed customer charges mitigate the effect of DERS on lost revenues or increased revenues. Similarly, demand charges might mitigate the effect of DERs on lost revenues or increased revenues, depending upon how the charge is structured and the extent to which the DER allows a customer to reduce payments for the demand charge.

[65] Some DG tariffs create a different dynamic regarding rate impacts. Some DG tariffs provide customers with bill credits for the DG output, which can be rolled over across billing periods or be used to support virtual or community solar programs. These bill credits are sometimes a better indication of DG lost revenues than reduced sales from the DG resource. (See Chapter 8.)

Rate impacts do not necessarily occur immediately upon installation and operation of DERs. Rates need to first be adjusted to reflect changes in costs or changes in sales. Some rate adjustments might occur fairly quickly (e.g., in the case of reconciling rate riders to recover EE program costs, or in the case of fuel and purchased power costs that are automatically passed through to customers in rate riders). Other rate adjustments might occur over a slightly longer period, e.g., in jurisdictions where there is decoupling, performance-based ratemaking adjustments, or lost revenue recovery mechanisms. Other rate adjustments might occur as a result of a rate case (for instance, in the case of reduced generation, transmission, and distribution costs, or in the case of sales adjustments). In the absence of rate adjustments, or until such time as all the rate adjustments are made, the impacts of DERs on costs and sales will be experienced by utility shareholders, not customers.

DER rate impacts can vary from year to year. Many DER costs are experienced in early years, whereas many DER benefits are experienced throughout the DER operating life. Consequently, rate impacts are sometimes greater in the short term than over the long term. A comprehensive understanding of rate impacts requires a long-term analysis of all the factors described above, consistent with the study period used for BCAs.

A.2 Cost-Effectiveness and Rate Impacts

In some cases, DER host customers will experience lower bills while those that do not install DERs may experience higher rates and therefore higher bills. Consequently, the rate impacts of DERs are a matter of customer equity between DER host customers and other customers.

Cost-effectiveness analyses, on the other hand, do not address customer equity. Cost-effectiveness analyses are focused on the benefits and costs to customers and the utility system as a whole.

Cost-effectiveness analyses should be conducted separately from rate impact analyses for the following reasons:

- First, cost-effectiveness analyses should account for only future, incremental benefits and costs, as required by the *Conduct Forward-Looking, Long-term, Incremental Analyses* principle. Rate impacts are driven by lost revenues, but lost revenues from DERs are not a new, incremental cost created by investments in those resources. Rate impacts from lost revenues are caused by the need to recover existing costs over fewer sales. These existing costs that would be recovered through rate increases are not caused by the DERs themselves: They are caused by historical investments in other utility resources that become fixed costs. In economic terms, these existing fixed costs are referred to as “sunk” costs. In economic theory, sunk costs should not be considered when assessing future investments because they are incurred regardless of whether the future investment is undertaken.
- Second, cost-effectiveness analyses are intended to answer a different question than rate impact analyses. Cost-effectiveness analyses are intended to answer the key question of *which utility DER investments are expected to have benefits that exceed costs*. Rate impact analysis are intended to answer the question of *how much will utility DER investments impact rates for one group of customers compared to another*. Attempting to answer these two questions in a single analysis conflates the two questions and thus does not provide helpful information on either one. The RIM Test, for example, combines DER lost revenues (which drive cost-shifting) with DER benefits and costs (which drive cost-effectiveness), to provide a set of metrics in the form of benefit-cost ratios and net benefits. However, these metrics say very little about cost-shifting and they confuse the issue of cost-effectiveness by including distributional effects.

Table A-1 presents a comparison of cost-effectiveness analyses and rate impact analyses.

Table A-1. Comparison of Cost-Effectiveness Analysis and Rate Impact Analysis

Key Considerations	Cost-Effectiveness Analysis	Rate Impact Analysis
Answers the question:	*Which utility DER investments are expected to have benefits that exceed costs?* Cost-effectiveness indicates the extent to which different utility investments will reduce utility costs and achieve other policy goals, regardless of how the benefits and costs are distributed across different customers.	*How much will utility DER investments impact rates for one group of customers compared to another?*[66]
Results of the analysis are expressed as:	Present value of revenue requirements, benefit-cost ratios, and net benefits. These metrics are important for regulators and other stakeholders to understand cost-effectiveness, but do not provide any information relevant to rate impacts.	Long-term impacts on rates (in ¢/kWh or percent changes to rates) or in terms of long-term bill impacts (in $ per month or percent changes to bills). These metrics are important for regulators and other stakeholders to understand rate impacts but do little to inform benefit-cost analyses.

Finally, it is important to note that many utility resource investments create rate impacts and customer equity issues. In addition, there are other aspects of electricity and gas regulation that create inequities, such as rate designs that are not fully cost-based. The issues discussed in this manual refer to only those equity issues that are created by DERs. Rate and equity concerns about DERs should be considered in light of the broader point that rate impacts and customer equity issues occur for many reasons beyond just DERs.

A.3 The Rate Impact Measure Test

The *California Standard Practice Manual* presents the Rate Impact Measure Test to account for rate impacts in EE cost-effectiveness analyses (CA PUC 2001). The RIM Test is the same as the UCT except that it includes the lost revenues from DER programs as one of the costs of the DER (or it includes the increased revenues as one of the benefits). (See Appendix E.)

Most jurisdictions have rejected use of the RIM Test for EE cost-effectiveness analyses, but many regulators and stakeholders continue to consider the results of this test and struggle with how to understand and address the rate impacts of EE resources. In recent years some studies of DER cost-effectiveness have used the RIM Test to assess the cost-effectiveness and rate impacts of other DER types.[67]

[66] Fully understanding the impacts across different customers requires a comparison of the bill impacts on host customers versus the bill impacts of other customers. (See Section A.4.)

[67] For an overview of BCA tests used for distributed solar resources, see ICF 2018.

The RIM Test can be useful for two purposes, both of which are related to rate impacts but not cost-effectiveness:

- To determine whether a DER or set of DERs is likely to increase or decrease rates; and
- To help inform whether a long-term rate, bill, and participation impact analysis is warranted.

For example, if a RIM Test result indicates that rates are likely to be reduced by DERs (with a RIM benefit-cost ratio of greater than 1.0) or rates are likely to be increased a small amount (with a RIM benefit-cost ratio of less than but close to 1.0) then there may be no need to conduct a rate, bill, and participation analysis. If, on the other hand, the RIM Test results indicate that rates are likely to be reduced by a significant amount (such as with a RIM benefit-cost ratio of less than 0.9) then a rate, bill, and participation analysis might be warranted.

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

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

A.4 Better Approaches for Analyzing Rate impacts

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

- *Rate impacts* indicate the extent to which rates for all customers might increase or decrease due to DERs.
- *Bill impacts* indicate the extent to which customer bills might be reduced for those customers that install DERs.
- *Participation impacts* indicate the portion of customers that will experience bill reductions or bill increases. DER host customers will typically experience bill reductions while other customers might see rate increases leading to bill increases.

Taken together, these three factors indicate the extent of the impact on customers from DERs, and also the extent to which DERs might lead to distributional equity concerns. It is critical to estimate the rate, bill, and participation impacts properly, and to present them in terms that are meaningful for considering distributional equity issues (SEE Action 2011).

Rate, bill, and participation analyses should be performed for DERs at an aggregated level, partly for the need to keep the analyses simple and accessible, and partly because customers will experience the rate impacts from DERs in an aggregated fashion. Further, regulators and other stakeholders may prefer to see rate, bill, and participation analyses that account for the impacts of all DERs combined because this offers the advantage of seeing how rate impacts of one DER type might offset, or exacerbate, rate impacts of other DER types.

A.4.1. Rate Impact Estimates

Rate impact estimates should account for all factors that impact rates. This would include all factors that might exert downward pressure on rates, as well as all factors that might exert upward pressure on rates. Any estimates of the impact of lost revenue recovery on rates should reflect collection of only those lost revenues necessary to recover fixed costs. In addition, rate impact estimates should reflect only the actual impact on rates according to the jurisdiction's ratemaking practices, such as decoupling, lost revenue recovery mechanisms, and the frequency of rate cases.

Rate impacts should be estimated over the long term, to capture the full period over which the efficiency savings will occur. The study period should include all the years in which DERs are installed and operational.

Rate impacts should also be put into terms that place them in a meaningful context, so that they can be properly considered and weighed by regulators and other stakeholders. For example, they should be put in terms of ¢/kWh impacts, dollars per month, percent of total rates, or percent of total bill.

Rate impacts can be markedly different across different customer types. Therefore, it may be necessary to analyze the rate impacts for different customer sectors. Conducting a rate impact analysis for every customer class is probably too burdensome and not necessary. Instead, analyses can be conducted for key customer types such as residential, small commercial, and large commercial and industrial.

A.4.2. Bill Impact Estimates

Bill impact estimates should build upon the estimates of rate impacts. While rate impacts apply to every customer within a rate class, bill impacts will vary between DER host customers and other customers. Further, bill impacts will vary depending upon the customer, the customer's rate design, the type of DER, and the way the DER is operated. For these reasons, it may be sufficient to conduct relatively high-level bill impact analyses.

As with rate impacts, bill impacts should be estimated over the long term, to capture the full period over which the DER is installed and operational. Bill impacts should also be put into terms that place them in a meaningful context, so that they can be properly considered and weighed by DER planners and regulators. For example, they should be put in terms of dollars per month or percent of total bill.

A.4.3. Participation Estimates

Participation estimates should be put in terms of participation rates, measured by dividing DER host customers by the total population of customers. Participation rates provide context and more meaningful information relative to a simple number of program participants. Participation rates can also be used to compare participation across DER initiatives, DER types, across utilities, and across jurisdictions.

Participation rates should be estimated for each year of DER implementation. They should be compared across many years to indicate the extent to which customers are participating in DERs over time. Participation in multiple DERs and across multiple years should be accounted for to the extent possible.

If program participation information is not currently available, it should be collected as soon as possible so that meaningful estimates can be developed in future years. This type of information is critical for assessing the customer equity issues, and hence the rate impact issues, of DERs.

Many equity concerns driven by rate impacts can be mitigated or even eliminated by promoting greater customer adoption of DERs, particularly EE, DR, and community solar programs that can be offered to all customers. Program participation information can be used to encourage more customers to install DERs and thereby experience lower bills. Utilities and other entities promoting DERs could be charged with the responsibility to reach those customers that have not yet implemented some form of DER.

A.4.4. Using the Results

There is no bright line to determine how to balance the cost-effectiveness results with the rate, bill, and participation analysis results. Nonetheless, the results of both analyses can be used to inform that balance. Regulators and other stakeholders can use these two types of analyses to assess whether any expected long-term rate impacts are warranted in light of the cost-effectiveness results, the bill reductions, and the participation rates.

Further, there are many different ways to address concerns about rate impacts once they are well understood. Regulators and other stakeholders may choose to modify proposed DER resources in order to strike a better balance between cost-effectiveness and equity issues. One option is to expand DER resources (especially EE and DR programs that can be offered to any customer) to include more participants and mitigate equity concerns. Another option is to revisit some of the DER designs to find ways to deliver them at lower cost (e.g., finding third-party financing or requiring host customers to pay larger portions of the DER cost). Another option is to shift priority from DERs that have low participation rates to those that have higher participation rates.

A.5 Presentation of Rate, Bill, and Participation Impacts

Figure A-1 provides an example of a useful way to present the results of a long-term rate impact analysis. This example shows the estimated long-term rate impacts, in terms of percent changes in rates, for six different DER types. It also shows the long-term rate impacts of all the DERs combined. In this example, the long-term rate increases from energy efficiency and distributed generation resources are essentially offset by the rate reductions from the other DER types.

Figure A-1. Example Presentation of Long-Term Rate Impacts

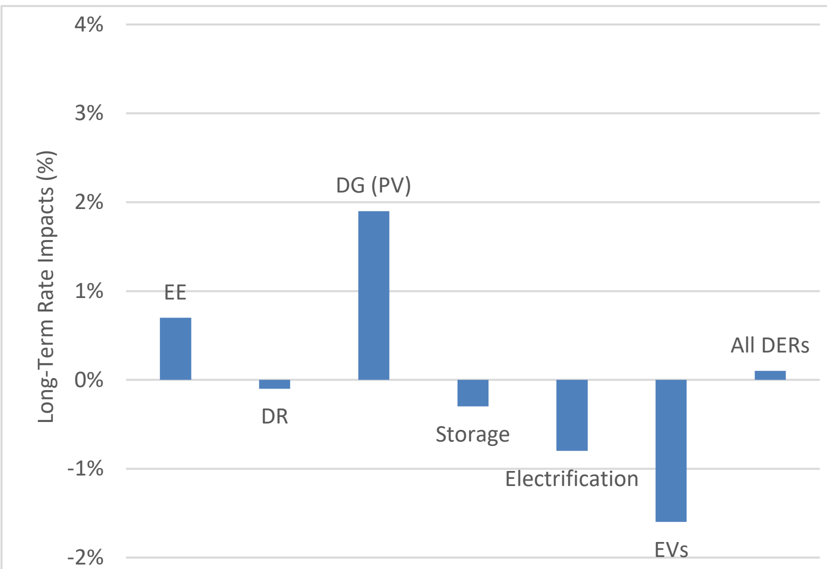


Figure A-2 provides an example of a useful way to present the results of a long-term bill impact analysis. This analysis includes the average bills across all utility customers, i.e., it includes the bills of both DER host customers and other customers. Also, for those resources that affect multiple fuel types, such as electrification and EVs, this analysis reflects the impact on the combined bills for all the fuels affected by the DER.

Figure A-2. Example Presentation of Long-Term Average Combined Bill Impacts

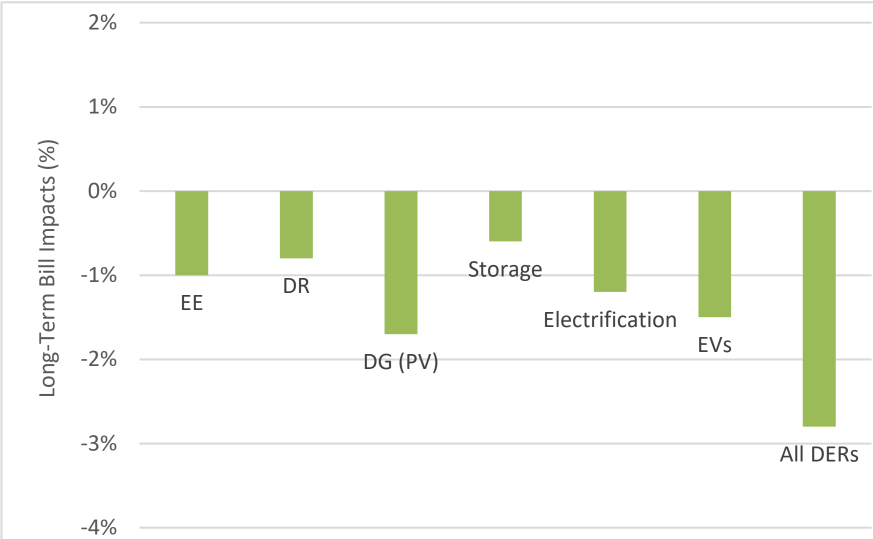
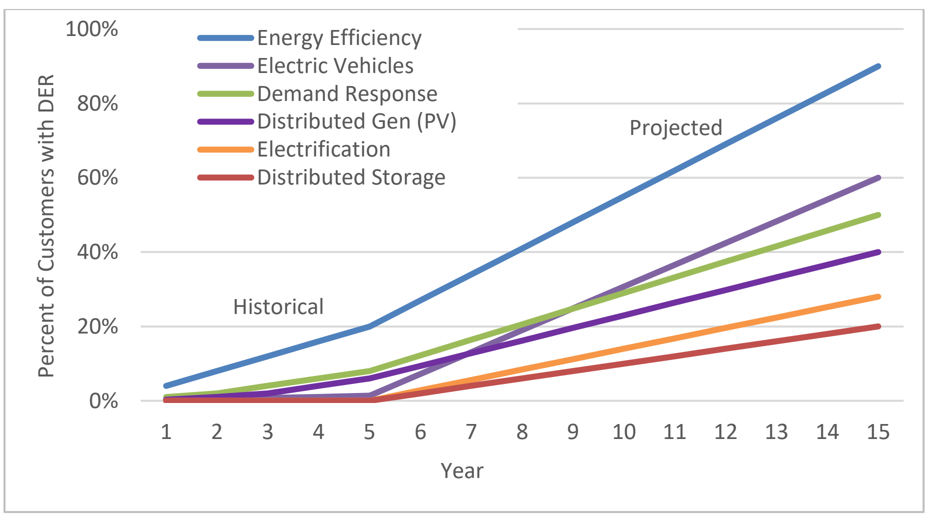


Figure A-3 provides an example of a useful way to present the results of a long-term participation analysis. It presents five years of historical DER participation rates, as well as 10 years of projections of future participation rates. Ideally, the participation rates would account for customers who participate in more than one program or install more than one type of DER. That would allow for the presentation of the percentage of DER host versus non-host customers, which would help inform discussions about customer equity.

Figure A-3. Example Presentation of Long-Term Participation Impacts



The DERs and long-term rate, bill, and participation results presented in these figures are purely illustrative and not based on specific DERs in a specific jurisdiction. Actual results could be significantly different from those presented here. Further, results will vary within the DER types presented here—the DER types are bundled together to simplify the figures.

Note also that for a given set of DERs these results will not vary depending upon which test is used because rate and bill impact estimates include only utility system benefits and costs; other benefits and costs will not affect rate or bill impacts.

Appendix B. Template NSPM Tables

This appendix provides example template tables that jurisdictions can use to take inventory of their applicable policies goals and objectives and to help identify relevant benefits and costs to inform development of their primary Jurisdiction-Specific Test.

The template tables presented or referenced in this appendix are intended to support jurisdictions in their efforts to articulate key assumptions and underlying information to inform development of their primary cost-effectiveness test (or modification to an existing test) using the NSPM Framework, and reporting results of their BCAs. These template tables can help to provide transparency in assumptions and processes used to conduct BCA in a jurisdiction.

Policy Inventory Tables

The *Policy Inventory Template Spreadsheet Tables* can help support jurisdictions in applying Step 1 of the NSPM BCA Framework, as well as informing Steps 2–4. The tables can help guide jurisdiction efforts to take inventory of applicable energy policies and identify associated relevant impacts to develop their primary test—the Jurisdiction-Specific Test—and to compare these to the jurisdiction's current cost-effectiveness testing practices.

This template table can be downloaded (in excel) at:
https://nationalenergyscreening.org/resources/templates/

Summary Benefit-Cost Analysis Results Table (for single DER)

This template table, illustrated on next page, can be used by jurisdictions to document the benefit and cost results from their BCA for a single DER program/project. Results are summarized by impact, by impact category, and in total, as well as net benefits and overall BCR.

The table provides the flexibility to display results of JSTs from any jurisdiction by providing space for that jurisdiction to include host customer and societal impacts to the extent that they are relevant (according to applicable policies) and included in that JST. There is also space to include non-monetized results of quantitative or qualitative data for economic development, market transformation, and other impacts.

This template table can be downloaded (in excel) at:
https://nationalenergyscreening.org/resources/templates/

Template Table: Summary Benefit-Cost Analysis Results

Single DER Program/Project Name:			**Date:**		
A. Monetized Electric Utility System Impacts	**Benefits**	**Costs**	**(A. cont.)**	**Benefits**	**Costs**
Generation: Energy Generation			Distribution: O&M		
Generation: Capacity			Distribution: Voltage		
Generation: Environmental Compliance			General: Financial Incentives		
Generation: RPS/CES Compliance			General: Program Administration Costs		
Generation: Market Price Effects			General: Utility Performance Incentives		
Generation: Ancillary Services			General: DG tariffs		
Transmission: Capacity			General: Credit and Collection Costs		
Transmission: System Losses			General: Risk		
Distribution: Capacity			General: Reliability		
Distribution: System Losses			General: Resilience		
			A. Sub-Total Electric Utility System Impacts	$ -	$ -
B. Monetized Host Customer Impacts	**Benefits**	**Costs**	**C. Monetized Societal Impacts**	**Benefits**	**Costs**
DER costs (host)			Resilience		
Transaction costs (host)			GHG Emissions		
Interconnection Fees	Include Host Customer Impacts to extent they are part of JST		Other Environmental	Include Societal Impacts to extent they are part of JST	
Risk			Economic and Jobs		
Reliability			Public Health		
Resilience			Low Income		
Power Quality			Energy Security		
Non-Energy Impacts (Host)			Energy Security Benefits		
Non-Energy Impacts (Low-income)					
B. Sub-Total Host Customer Impacts	$ -	$ -	***C. Sub-Total Societal Impacts***	$ -	$ -

D. Total Monteized Benefits and Costs	**Total Present Value ($)**	**Benefit-Cost Ratio**	
Total Benefits	$ -		
Total Costs	$ -		
Net Benefits or Costs	$ -	**0.0**	

E. Non-Monetized and Qualitative Assessments		
Economic Development and Job Impacts	*Provide quantitative information and discussion of assessment/how considered*	
Market Transformation Impacts	*Describe qualitative considerations and describe how considered*	
Other Non-Monetized Impacts	*Provide quantitative information, qualitative considerations, and describe how considered*	
COST-EFFECTIVENESS DETERMINATION:	***Do DER Benefits Exceed Costs?***	***[Yes/No]***

Jurisdictions can use these template tables as is or can expand and modify them to meet their specific needs in documenting key assumptions and results from their BCA.

Appendix C. Approaches to Accounting for Relevant Impacts

This appendix describes different approaches that jurisdictions can use to account for relevant benefits and costs, including those that are hard to quantify or hard to monetize. It also describes how to use quantitative and qualitative information in the absence of monetary values. The appendix provides a sample of existing tools and resources/studies for how to quantify impacts, as well as some information on general methodologies.

C.1 Introduction

Benefits and costs of DER investment may be estimated in monetary or other non-monetary quantitative terms or qualitative values. Although using monetary values provides consistency for direct comparison of DER impacts, some impacts are hard to monetize. Jurisdictions also face constraints to conducting rigorous jurisdiction-specific impact studies and may therefore choose to apply other approaches such as estimating values based on studies from other jurisdictions, determining proxies, or using alternative thresholds. This appendix discusses these considerations and also provides examples of existing studies and tools for quantifying DER impacts.

For impacts that are hard to monetize, identifying other approaches to including these impacts in tests as quantitative or qualitative data can be necessary in order to treat benefits and costs symmetrically.

Table C-1 summarizes five approaches that can be used to account for relevant and material impacts of DERs that a jurisdiction has chosen to include in its cost-effectiveness test. These are each discussed in the following sections.

Table C-1. Different Approaches to Account for Relevant Impacts

Approach	Description
Monetary Approaches:	
Jurisdiction-specific studies	Rigorous jurisdiction-specific studies on DER impacts offer the potentially most accurate approach for estimating and monetizing relevant impacts.
Studies from other jurisdictions	If jurisdiction-specific studies are not available, studies from other jurisdictions or regions, or national studies, can be used for estimating and monetizing impacts.
Proxies	If monetized impacts are not available, well-informed and well-designed proxies can be used as a simple substitute (e.g., % adders).
Non-Monetary Approaches:	
Alternative thresholds	Pre-determined thresholds, e.g., BCRs that are different from one (1.0), can be used as a simple way to account for relevant impacts that are not otherwise included.
Accounting for non-monetized impacts	Relevant qualitative information can be used to estimate impacts that cannot be monetized.

C.2 Monetary Values

All DER impacts that a jurisdiction has chosen to include in its cost-effectiveness tests should ideally be estimated in monetary terms. Monetary values provide a uniform way to compile, present, and compare benefits and costs. While some DER impacts are difficult to quantify in monetary terms—either due to the nature of the impact or the lack of available information about the impacts—informed approximation of hard-to-quantify impacts (i.e., not using arbitrary values) is preferable to assuming that the relevant benefits and costs do not exist or have no value. Further, some approximation may be necessary to ensure symmetry in the treatment of benefits and costs for certain relevant impacts.

Estimating impacts in monetary terms for utility system impacts, other fuel impacts, and non-utility system impacts require the following considerations:

- *For electric and gas utility system impacts*, monetary values should be in terms of utility revenue requirements so that the values will indicate the effect of the benefits and costs on the utility customers in each year. Costs that occur on an annual basis and are collected by utilities each year should be accounted for in the year they are collected from utility customers. Capital costs should be amortized over the regulatory book life of the investment. This will turn a single capital investment in one year into a stream of annual revenue requirements over that book life. Those annual revenue requirements should properly reflect the ratemaking treatment for capital costs in the relevant jurisdiction, including recovery of depreciation, taxes, debt, and equity.
- *For other fuels impacts*, monetary values should be based upon the retail price of those fuels. The retail price typically reflects the annual marginal costs of providing those resources.
- *For other non-utility system impacts*, monetary terms should be used as much as possible. For example, host customer impacts and third-party impacts should be put in monetary terms for the years in which they are incurred.

C.2.1. Jurisdiction-Specific Studies

Jurisdiction-specific studies are the most rigorous and reliable way to estimate the benefits and costs of DERs in that jurisdiction. These studies typically use local information to the greatest extent possible, by utility, by state, by province, or by the relevant Regional Transmission Organization/Independent System Operator. These studies are derived from, or at least be consistent with, the most recent integrated resource planning studies available, wherever they exist. More information on tools and studies is available in Section C.5 below.

Utility System Impacts

Avoided cost studies. These studies are frequently conducted to quantify DER benefits, in particular the utility system benefits. These studies are typically jurisdiction-specific to ensure that they accurately capture the operations and the impacts of the utility system where the DERs will be installed. The studies should be comprehensive by addressing the full range of utility system impacts (see Chapter 4). Further, best practice for conducting avoided cost studies includes use of all relevant information available at the time of study, ensuring periodic updates to reflect the most recently available information, and transparency in underlying input assumptions used to calculate the avoided costs.

Avoided cost studies require many detailed assumptions and comprehensive/complex methodologies, and they typically produce detailed results. For regulators, utilities, and other stakeholders to properly assess and understand avoided cost studies and implications for BCAs—to ultimately ensure that BCA conclusions are reasonable and robust—key inputs, assumptions, methodologies, and results should be clearly documented in sufficient detail to allow for review by key stakeholders and ultimately by regulators via a jurisdiction's specific process.[68]

Host Customer and Societal Impacts

Impact Studies: Host customer (participant) impact studies estimate a range of benefits to customers that invest in a DER. To date, participant impact studies mostly pertain to the impacts of energy efficiency programs, and frequently they apply to one or more program sectors such as residential or industrial.

Host customer and societal impact studies may use one or a combination of several approaches to data collection, including self-reporting e.g., through surveys, direct measurement such as from a meter, and using secondary data collected from other industries, such as insurance filings. Once collected, this data may be applied to assess program impacts through basic aggregation, engineering analyses to extrapolate impacts beyond the data collected, and complex economic models.

As with avoided cost studies, conducting host customer and societal impact studies can involve comprehensive studies, which typically entail statistical analyses and triangulation of various estimation methods. For regulators, utilities, and other stakeholders to properly assess and understand these impacts and their implications for BCAs, key inputs, assumptions, methodologies, and results should be clearly documented in sufficient detail to allow for review by key stakeholders and ultimately by regulators through a jurisdiction's specific process.

C.2.2. Studies from Other Jurisdictions

In some cases and for some impacts, a jurisdiction-specific study might not be available for some of the information needed for a BCA. In these cases, it may be appropriate to use results from other jurisdictions. This could include studies prepared for other utilities, other states, other jurisdictions, or other regions. It could also include regional or national studies that do not necessarily focus on any one jurisdiction or region.

However, DER planners must take care to ensure that the value of a particular benefit or cost in another jurisdiction is equal to, or sufficiently comparable to, the value in the jurisdiction of interest. If not, it may be necessary to adjust values from other jurisdictions before using them. For example, labor costs in one part of the country might be significantly different from other parts of the country. These differences can be accounted for by adjusting values according to an agreed-upon methodology.

Lawrence Berkeley National Laboratory has developed a list of jurisdiction-specific studies currently used to quantify NEIs in EE cost-effectiveness tests, as well as information on the transferability of the values and/or methodologies produced in the studies (LBNL 2020a).

[68] See as an example the New England Avoided Energy Supply Cost studies (AESC Study Group 2018). Another example is the California Public Utility Commission cost-effectiveness calculator that embeds the state's official avoided costs in a model to calculate cost-effectiveness (CPUC 2016).

C.2.3. Proxies

For the purpose of DER BCAs, a proxy is a simple, quantitative value that can be used as a substitute for a value that is not monetized by conventional means. Proxies 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 are typically based on professional judgment; but they should not be developed or perceived as arbitrary values. Proxies should be developed by making informed approximations based upon the best information currently available regarding the relevant impact. This should include a review of relevant literature on the specific impact, as much quantification of the impact that is both feasible and reasonable, a review of proxy values used by other jurisdictions, and consideration of conditions specific to the relevant jurisdiction.

To date, proxies have most frequently been used to account for DER benefits such as low-income benefits, participant non-energy benefits, or risk benefits (NESP 2019). However, proxies can be used for all DER impacts.

Level of Application

Proxy values can be developed for different levels of application, ranging from a single proxy value that applies to an entire portfolio of DERs to different proxy values for each DER impact.

When choosing the level of detail to apply to a proxy, there may be a tradeoff between accuracy and feasibility. Proxies that are more detailed are likely to more accurately represent the magnitude of the specific impact in question. However, proxies that are more detailed are also likely to require more information and greater costs to develop.

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

Type of Proxy

Several different types of proxies can be used to account for DER impacts.

- *Percentage Adder:* A percentage adder approximates the value of non-monetized impacts by scaling up impacts that are monetized. This type of proxy is the simplest and easiest to apply.
- *Electricity Savings Multiplier ($/MWh):* An electricity savings multiplier approximates the value of non-monetized benefits or costs relative to the quantity of electricity saved by a DER.
- *Gas Savings Multiplier ($/therm):* A gas savings multiplier approximates the value of non-monetized benefits or costs relative to the quantity of gas saved by a DER. It offers the same advantages and disadvantages of electricity multipliers.
- *Fuel Savings Multiplier ($/MMBtu):* A fuel multiplier approximates the value of non-monetized benefits or costs relative to the total quantity of fuel saved by a DER, regardless of the type of fuel saved (e.g., electricity, gas, oil, propane).
- *Customer Adder ($/customer):* A customer adder (or subtraction) approximates the value of non-monetized benefits relative to the number of customers served by a DER program.

- *Measure Multiplier ($/measure):* A measure multiplier (positive or negative) approximates the value of non-monetized benefits or costs relative to the number of measures implemented as part of a DER program.

As with the choice of level of application for a proxy, the choice of which type can result in a tradeoff between accuracy and feasibility. Proxies that are more focused (e.g., by measure, by customer, or by fuel) are more likely to accurately represent the magnitude of the specific impact in question. However, proxies that are more focused are also likely more difficult and expensive to develop.

C.3 Non-Monetary Values

Once all efforts to monetize DER impacts have been considered and exhausted, the following steps can be used to consider additional quantitative and qualitative non-monetary information.

Distinguish between whether and how to include an impact

Regulators and stakeholders will sometimes decide not to include a certain benefit or cost in the primary test because the impact is assumed to be too small, too uncertain, or too hard to quantify. A better approach is to first decide *whether* to include impacts in cost-effectiveness tests based on the fundamental cost-effectiveness principles, and then decide separately *how* to value or otherwise account for the impacts.

This distinction between whether to include something and how to include it is very important. This is partly because it allows for a more transparent application of the fundamental BCA principles, partly because an impact that is small and immaterial today might become large and material in the future, and partly because an impact that is small and immaterial for one DER might be large and material for another DER. Once the decision has been made regarding whether to include an impact in the primary test, then a secondary decision can be made as to how to account for it. If an impact is assumed to be so small as to be immaterial, then it should be included in the test but assigned a value of zero.

Provide as much quantitative evidence as possible

For those impacts that remain non-monetized, it may be possible to put them into quantitative terms. Quantitative values generally provide more concrete information for decision-makers to consider, relative to qualitative values or no values at all. Quantitative values of DER impacts should be documented in detail, along with justification for why and how the values are relevant to the cost-effectiveness analysis.

For example, jurisdictions that choose to include job impacts might want to present this impact in terms of the number of job-years, rather than a monetized value for jobs. Regulators and distribution planners could then compare different energy resources according to how many job-years are created by each one.

Establish metrics to create quantitative data for future analyses

Metrics offer a quantitative way to assess the extent of a benefit or cost, in the absence of monetary values for this purpose. For example, if the utility does not monetize safety, resilience, or power quality benefits for its BCA, regulators can establish metrics to indicate the extent to which these benefits will be experienced. The data obtained over time for these metrics can be used for BCAs in future years.

Provide as much qualitative evidence as possible

Those impacts that are not monetized or quantified should be addressed qualitatively. Qualitative information can provide some information for decision-makers to consider, relative to no information at all. For those DER impacts that are addressed qualitatively, distribution planners should develop and present as much qualitative evidence as possible regarding those impacts. This evidence should also include a justification for why the considerations are relevant to the cost-effectiveness analysis.

For example, a jurisdiction might choose to consider incremental market transformation benefits without quantifying or monetizing such benefits. In this case, regulators or distribution planners would consider the incremental market transformation benefits, without necessarily estimating what those benefits are either in terms of energy savings or dollar savings.

Decide upon the implications of the quantitative and qualitative evidence

Any non-monetized impacts of DERs should be presented along-side the monetary impacts. This allows the regulators and other decision-makers to compare the monetized, quantitative, and qualitative factors and evidence to decide whether a DER is cost-effective. In some cases, the monetary results alone might be sufficient to make this decision (for instance, if the monetary benefits exceed the monetary costs, and all the non-monetary evidence indicates there will be additional benefits). The cost-effectiveness decision might also be easy if the monetary benefits are slightly less than the monetary costs, but the non-monetary benefits are clearly significant enough to make up the difference.

In other cases, the decision might not be so clear. For example, if the monetary benefits do not exceed the costs, then the non-monetary benefits are not necessarily significant enough to make up the difference. In these cases, regulators and other decision-makers should make a cost-effectiveness determination, based on all the evidence presented, and with input from relevant stakeholders.

Document and justify the decision

Finally, the cost-effectiveness decision should be fully documented and justified. This is necessary to provide transparency regarding the decision for the resource in question, and to provide guidance on how similar decisions will be made in future BCAs.

C.4 Alternative Thresholds

Alternative thresholds are another approach for addressing hard-to-monetize impacts. They allow DERs to be considered cost-effective at pre-determined benefit-cost ratios that are different from one (1.0). Regulators can apply a benefit-cost ratio of greater than one (1.0) to account for DER costs that have not been monetized, or a benefit-cost ratio of less than one (1.0) to account for benefits that have not been monetized.

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. Rather, it provides a general reflection of the regulators’ willingness to be flexible in accounting for certain impacts.

Using alternative benchmarks can essentially have the same effect as applying a proxy value. For example, an alternative portfolio-level benefit-cost ratio benchmark of 0.9 is equivalent to a portfolio-level benefit multiplier of 11 percent; and an alternative benefit-cost ratio benchmark of 0.8 is equivalent to a benefit multiplier of 25 percent.

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.

C.5 Tools and Studies to Support Estimation of Impacts

A variety of tools and studies exist to help local utilities, regulators, policymakers, and other stakeholders estimate and document quantified impacts of DER programs, policies, and investments in their jurisdictions.[69]

Studies on Multiple DERs

Most research on impact quantification to date exists for EE programs, so many of the resources listed in this section pertain to energy efficiency. However, there is a growing list of publications to support estimation of impacts for multiple DERs, including:

- *How Distributed Energy Resources Can Improve Resilience in Public Buildings: Three Case Studies and a Step-by-Step Guide* (DOE 2019d),
- *Energy Efficiency and Distributed Generation for Resilience: Withstanding Grid Outages for Less* (DOE 2019a),
- *Capturing More Value from Combinations of PV and Other Distributed Energy Resources* (RAP 2019a), and
- The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices (NARUC 2019).

Tools

EPA maintains the *Publications, Tools, and Data for State, Local, and Tribal Governments* webpage that includes resources to support energy policy-making, program implementation, and evaluation. The tools available on this page include the AVoided Emissions and geneRation Tool (AVERT), which supports air emissions impact estimation (2018), the Environmental Benefits Mapping and Analysis Program (BenMAP-CE), which calculates the economic and public health impacts of air pollution (2018), and the CO-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool for estimating the health and economic benefits of clean energy policies (2018).

Impacts studies

The studies listed below provide a sample of existing methodologies for estimating one or multiple EE impacts at the utility system, host customer, or society level. Therefore, they are organized below by the level of impact studied.

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69 This list of tools resources is current as of the Summer 2020 publication of this NSPM and is not an exhaustive list of available resources.

Utility System Impacts studies

- Avoided Energy Supply Components in New England: 2018 Report (Synapse Energy Economics, Resource Insight, Les Deman Consulting, North Side Energy, and Sustainable Energy Advantage. 2018)
- Keeping the Lights On: Energy Efficiency and Electric System Reliability (ACEEE, 2018)
- Everyone Benefits: Practices and Recommendations for Utility System Benefits of Energy Efficiency. (ACEEE, 2015)
- Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements (RAP, 2011)

Multiple benefits studies (Host Customer Impacts, Societal Impacts)

- Making Health Count: Monetizing the Health Benefits of In-Home Services Delivered by Energy Efficiency Programs (ACEEE, May 2020)
- Public Health Benefits per kWh of Energy Efficiency and Renewable Energy (EPA, 2019)
- Cost-Effectiveness Tests: Overview of State Approaches to Account for Health and Environmental Benefits of Energy Efficiency (ACEEE, 2018)
- Saving Energy, Saving Lives: The Health Impacts of Avoiding Power Plant Pollution with Energy Efficiency (ACEEE, 2018)
- Analysis of the Public Health Impacts of the Regional Greenhouse Gas Initiative (Abt Associates, 2017)
- Occupant Health Benefits of Residential Energy Efficiency (E4TheFuture, 2016)
- Home Rx: The Health Benefits of Home Performance (DOE, 2016)
- State and Utility Pollution Reduction Calculator Version 2 (SUPR 2) (ACEEE, 2016)
- ACEEE State Policy Toolkit: Guidance on Measuring the Economic Development Benefits of Energy Efficiency (ACEEE, 2019)
- Quantifying the Multiple Benefits of Energy Efficiency and Renewable Energy (US EPA, 2018)
- Non-energy Benefits in State Cost-Effectiveness Tests – Reducing Bias in Consideration of Energy Efficiency as a Resource (Skumatz, 2018)
- The Cost of Saving Electricity Through Energy Efficiency Programs Funded by Utility Customers: 2009-2015 (Hoffman, I., C. Goldman, S. Murphy, N. Mims, G. Leventis, and L. Schwartz., 2018.)
- Assessing the Cost Effectiveness of Energy Efficiency Portfolios (LBL, 2017)
- Non-energy Impacts Approaches and Values: An Examination of the Northeast, Mid-Atlantic, and Beyond (NEEP, 2017)
- Evaluating and Quantifying the Non-Energy Impacts of Energy Efficiency (LBL Webinar, 2016)
- Recognizing the Value of Energy Efficiency's Multiple Benefits (ACEEE, 2015)
- Recognizing the Full Value of Energy Efficiency (RAP, 2013)
- Energy Efficiency Cost-Effectiveness Screening How to Properly Account for 'Other Program Impacts' and Environmental Compliance Costs (RAP, 2012)

Appendix D. Presenting BCA Results

This appendix provides guidance on how to present results in ways that are most informative and most useful in making cost-effectiveness decisions. It also provides guidance on how to present results to support efforts to prioritize across different DER types.

D.1 Introduction

There are multiple ways of presenting the results of BCAs, each with different strengths and limitations. The primary options are described in the following subsections.

The examples below illustrate how to present some of the most useful information from cost-effectiveness analyses. The DERs and cost-effectiveness results presented in examples below 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. Further, some DER types are bundled together to keep the figures from being too complex.

D.2 Present Values of Benefits and Costs

The present value of the benefits and costs serve as the foundation for BCA results. It is often useful to start by presenting the costs separately from the benefits before combining them into net benefits or benefit-cost ratios.

It is also useful to present the stream of annual present value costs and the stream of annual present value benefits to provide a complete picture of how they play out over time.

Then the two streams of annual present value benefits and costs should be accumulated over the study period to determine the cumulative present value of benefits and the cumulative present value of costs.

It is also useful to present the annual streams of *cumulative* present values of benefits and costs, in order to indicate which year, if ever, the cumulative benefits exceed the cumulative costs. The number of years it takes for the cumulative benefits to exceed cumulative costs provides an indication of the "payback" period. In general, resources with shorter payback periods are more cost-effective than those with longer payback periods.

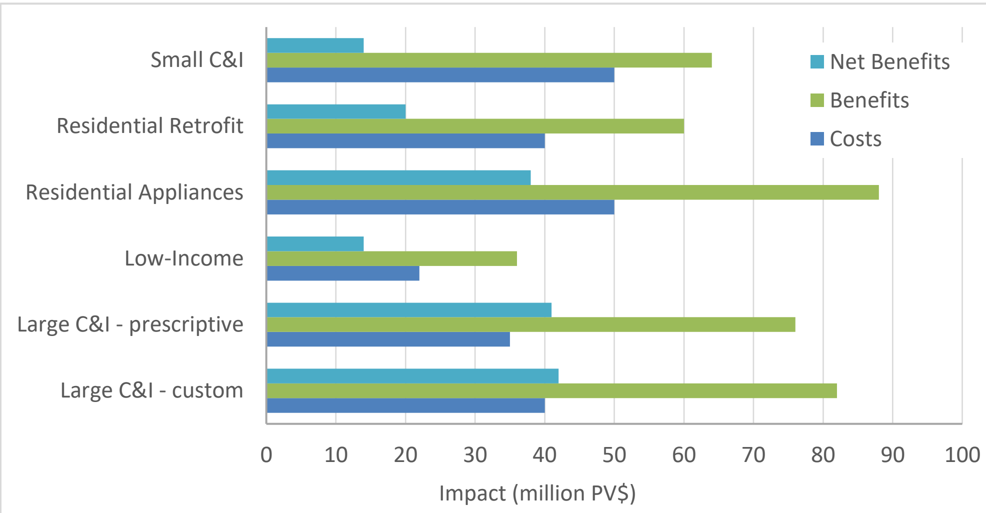
D.3 Net Benefits

Net benefits are equal to the difference between the cumulative present value of benefits and the cumulative present value of costs, as per the formula below. This metric is useful as a benchmark for determining cost-effectiveness: If a DER's net benefits are greater than zero, its benefits exceed its costs, and it is considered cost-effective.

$$\text{Net Benefits (dollars)} = \text{NPV} \sum \text{benefits} - \text{NPV} \sum \text{costs}$$

Figure D-1 provides an example of a useful way to present costs, benefits, and net benefits of an illustrative set of EE programs. Similar graphs could also be developed for other DER programs, other EE programs and/or combinations of EE and other DER programs. In this hypothetical example, the Large C&I program offers the greatest net benefits, and the Deep Energy Retrofit program has negative net benefits and is therefore not cost-effective. Of course, actual EE programs might have very different results than the examples presented here.

Figure D-1. Example Presentation of Costs, Benefits, and Net Benefits: Hypothetical EE Resources



The net benefits metric provides important information that is not provided by a benefit-cost ratio, by indicating the magnitude of the benefits to be gained by the efficiency resource. For example, a BCR of 2.2 does not indicate how much money will be saved by the resource. It might save $1 million, $10 million, or $100 million.

On the other hand, the net benefits of DERs cannot easily be used to compare DERs across different utilities and jurisdictions. A large utility would naturally expect to have higher net benefits than a small utility for a comparable DER.

D.4 Benefit-Cost Ratio

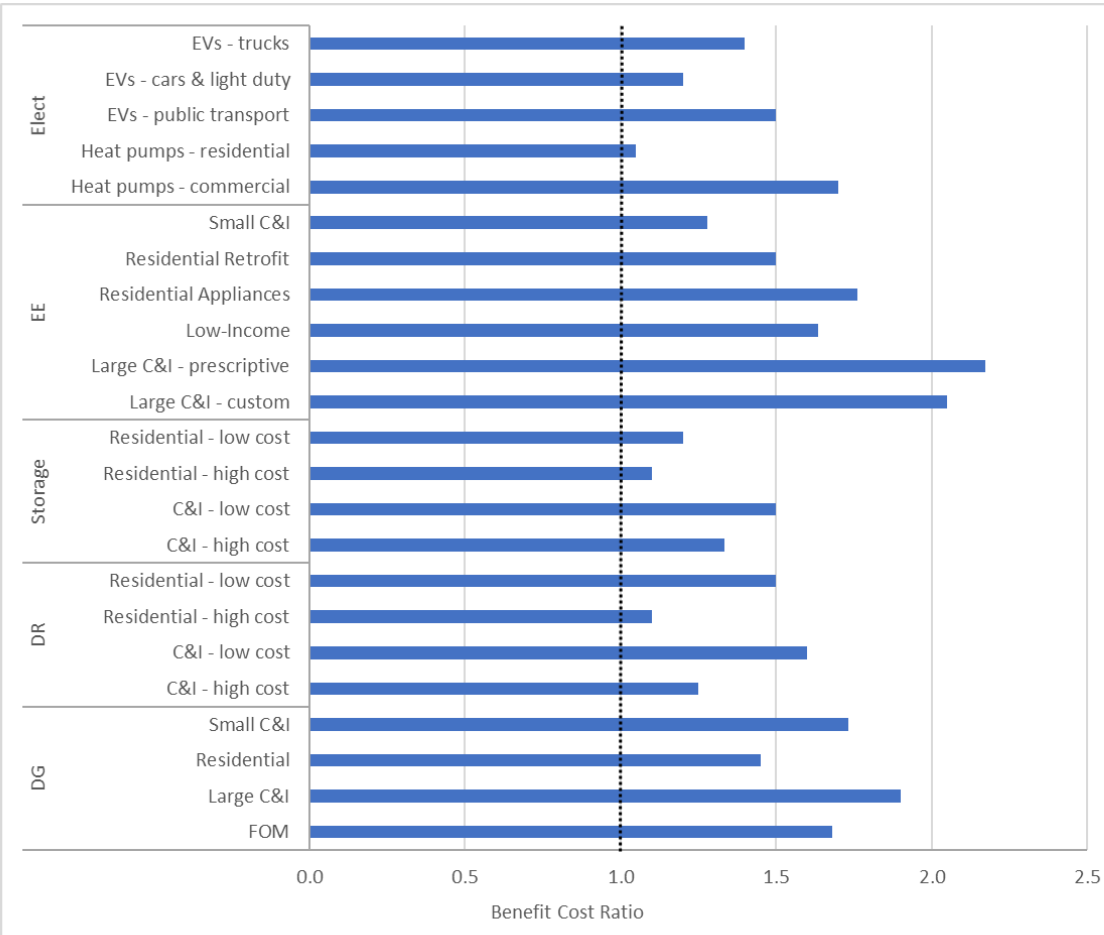
A benefit-cost ratio is equal to the ratio of the cumulative present value of benefits to the cumulative present value of costs, as per the formula below. This metric is useful as a simple benchmark for determining cost-effectiveness: If a DER's BCR exceeds 1.0, its benefits exceed its costs, and it is considered cost-effective.

$$\text{Benefit-Cost Ratio} = \frac{\text{NPV} \sum \text{benefits (dollars)}}{\text{NPV} \sum \text{costs (dollars)}}$$

The BCR metric can be useful for comparing DERs with each other (i.e., a higher BCR indicates one resource is "more cost-effective" than another), because it effectively normalizes the results for DERs of different sizes. This metric is also useful for comparing DERs across utilities and jurisdictions of different sizes, again because it effectively normalizes the results for any differences in size.[70]

Figure D-2 provides an example of a useful way to present benefit-cost ratios. This example includes a variety of hypothetical DER types. If multiple DERs are presented in a single graph in this way, it is important that the cost-effectiveness test and the inputs for each DER are consistent. For example, if the host customer benefits and costs are included in the costs for one DER type, then they should be included for all DER types.

Figure D-2. Example Presentation of Benefit-Cost Ratios: Hypothetical Multiple DERs



The BCR metric provides important information that is not provided by a net benefits metric. It does this by indicating the relative effectiveness of the money spent on the resource. i.e., how many dollars of benefits are received per dollar spent. For example, a net benefit of $10 million in present value dollars (PV$) does not indicate how much money was needed to generate those net benefits. It could have cost $90 million, with benefits of $100 million and a BCR of 1.1. Or it could have cost $4 million, with benefits of $14 million and a BCR of 3.5.

[70] However, in making such comparisons it is important to recognize that different utilities and jurisdictions might have different avoided costs, i.e., different benefits for the same amount of savings. Different jurisdictions might also include different impacts in their resource assessment test.

D.5 Levelized Costs

D.5.1. Levelized Cost Calculations

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. Levelized costs represent the average cost per unit of energy required to install and operate an electricity or gas resource. They include the costs of the resource over its economic operating life, amortized over the lifetime and discounted back to the first year divided by the total lifetime energy produced (Lazard 2019).

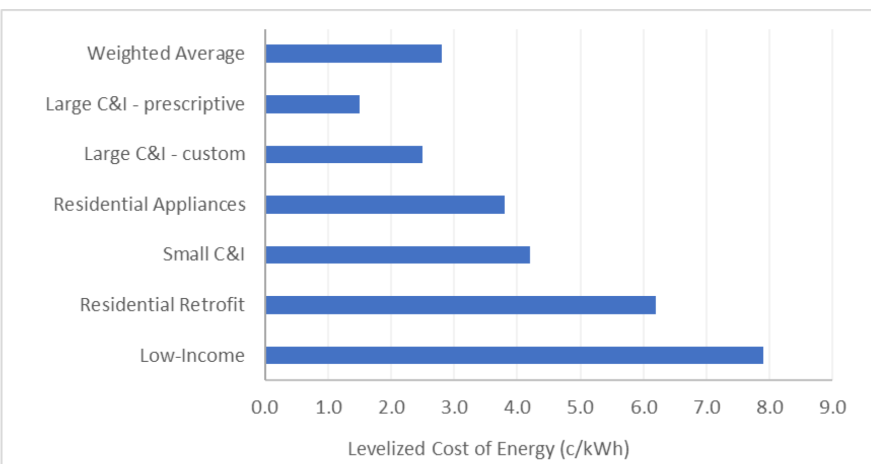
Levelized costs for electricity generation resources are commonly referred to as levelized cost of electricity (LCOE) (EIA 2019). Levelized costs for efficiency resources are commonly referred to as levelized cost of saved energy (LCSE) (LBNL 2018). They are calculated using the following formulas:

> 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
>
> n = the resource lifetime

This manual uses the term "levelized cost of energy" to refer to both LCOE and LCSE interchangeably.

Figure D-3 provides an example of a useful way to present LCOE for EE resources.

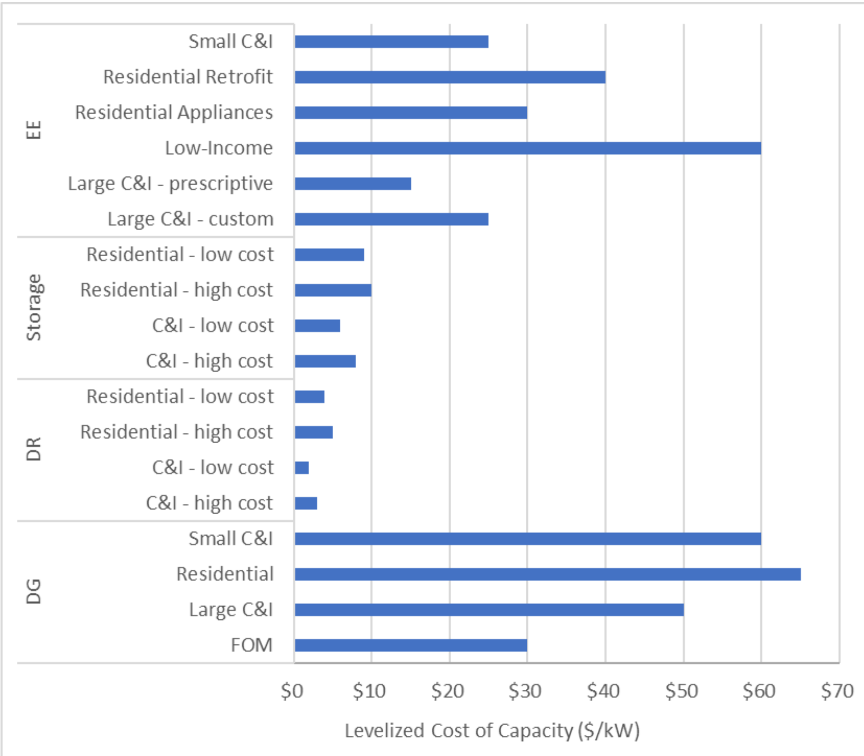
Figure D-3. Example Presentation of Levelized Cost of Energy: Hypothetical EE Resources



While the levelized cost of energy is a useful way to present the *costs* of electricity and gas resources, it only tells part of the story. It says little about the *benefits* of the resources. It puts all the costs in terms of generation benefits (MWh), but says nothing about generation capacity (kW) benefits. It also says nothing about T&D benefits, risk, reliability, other fuel, host customer, or societal benefits.

Levelized costs can also be used to indicate capacity impacts by calculating a levelized cost of capacity (in $/kW). This is especially useful for resources whose primary function is to provide capacity services. It is calculated the same way as the LCOE, except that annual generation is replaced with annual peak savings. Figure D-4 provides an example of a useful way to present levelized cost of capacity for several illustrative DERs.[71]

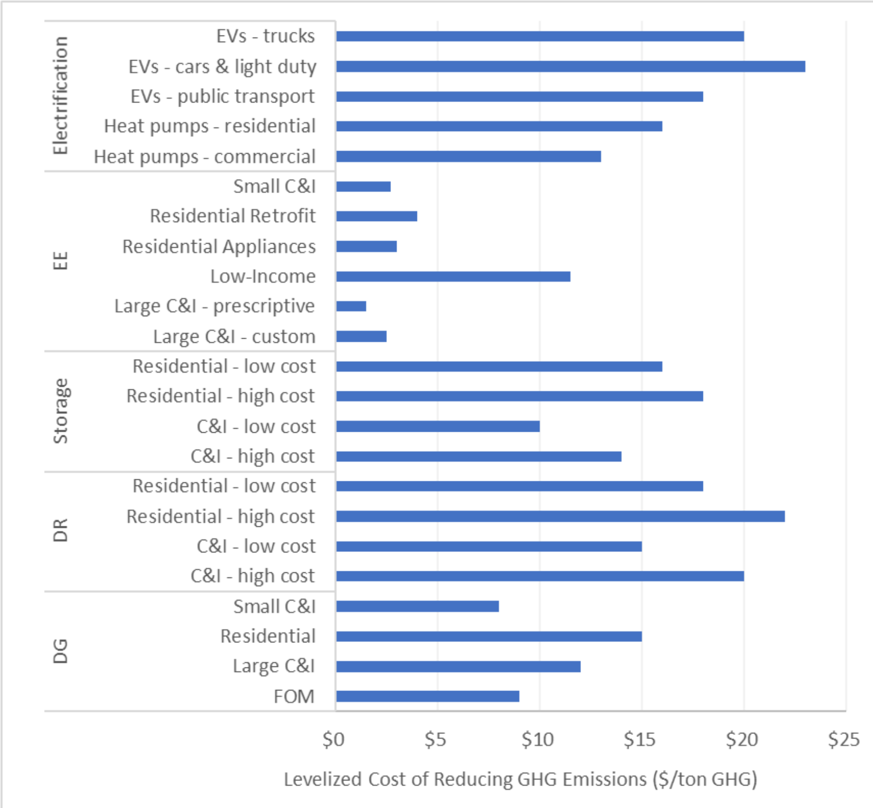
Figure D-4. Example Presentation of Levelized Cost of Capacity: Multiple DERs



Similarly, levelized costs can also be used to indicate carbon reduction impacts by calculating a levelized cost of carbon reduction (in $/ton of GHG reduced). This is especially useful for indicating which resources are most effective at reducing carbon emissions for the dollar spent. It is calculated the same way as the levelized cost of energy, except that annual generation is replaced with annual GHG reductions (or increases). Figure D-5 provides an example of a useful way to present levelized cost of GHG reduction for several illustrative DERs.

[71] This figure does not include levelized cost of capacity for electrification DERs because these resources typically do not save capacity.

Figure D-5. Levelized Cost of GHG Reduction: Multiple Hypothetical DERs



LCOE, capacity, and GHG reduction all provide different information about the impacts of DERs. For those jurisdictions interested in avoiding capacity costs and reducing GHG emissions, in addition to avoiding energy costs, it would be most informative to calculate and consider all three of these metrics.

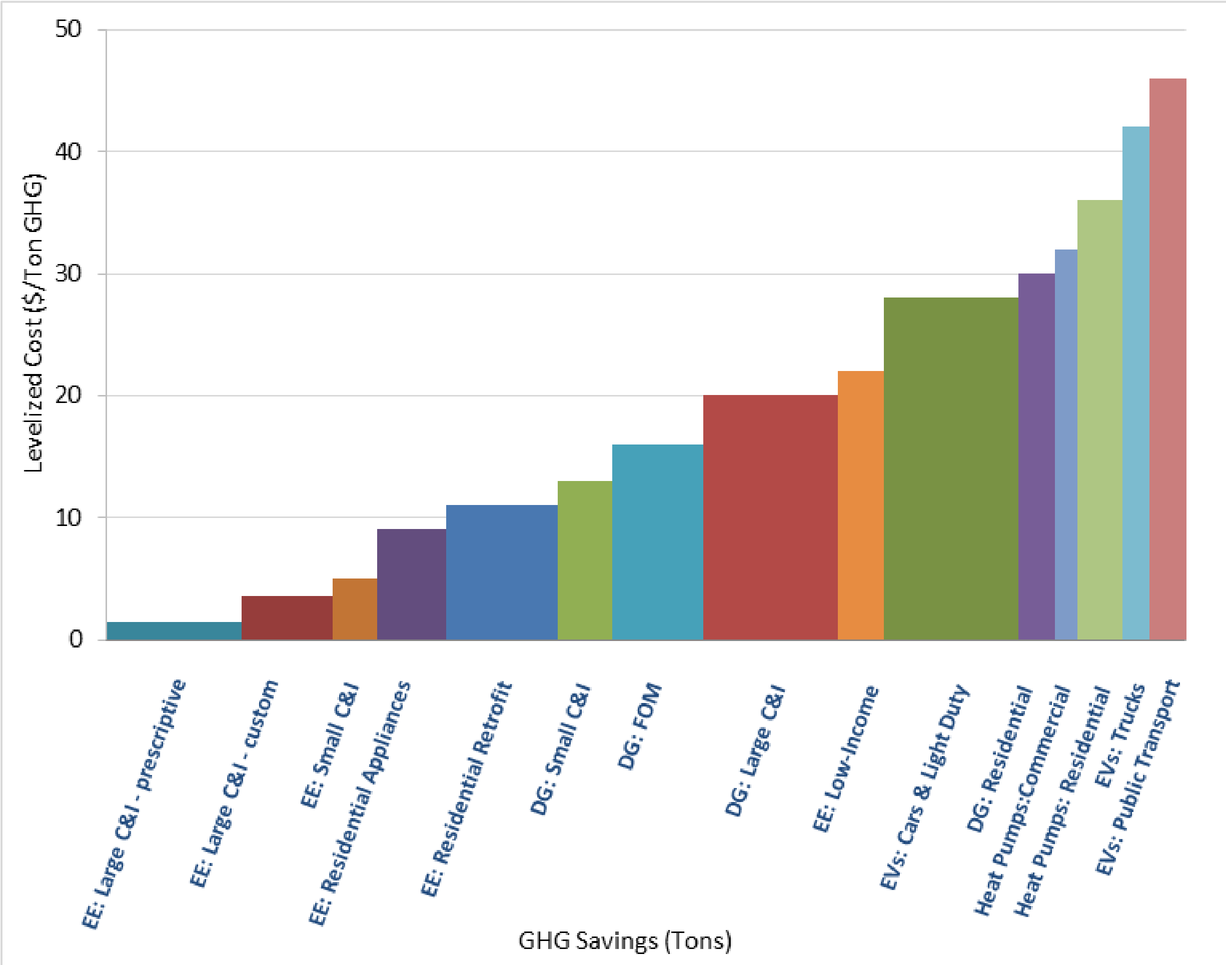
Finally, it is important to recognize the limitations of levelized costs of any type. They do not account for certain benefits that might be included in a jurisdiction's primary test, including risk, other fuel impacts, low-income benefits, host customer benefits, or societal benefits. Therefore, while levelized costs have some usefulness for comparing different DERs to each other, they should not be used in isolation for determining whether a DER is cost-effective. Also, while levelized costs can help prioritization across DERs, it may be important to also consider other comparisons that account for other differences in DER benefits.

D.5.2. Levelized Cost Curves

DER cost curves offer a useful way to compare DERs. Cost curves are a graphic depiction of levelized costs where a bar chart is used to depict (a) the DER levelized costs, sorted lowest to highest cost, and (b) the magnitude of the savings for each DER. Typically, the levelized costs are represented on the vertical axis, while the magnitude of savings is presented on the horizontal axis, where the width of each bar indicates the amount of savings.

There are many types of cost curves that can be created to inform DER cost-effectiveness decision-making. Figure D-6 presents an example of a GHG cost curve.

Figure D-6. Example of GHG Cost Curve: Hypothetical Set of Multiple DER Types



Cost curves like the one above are subject to the same limitations as levelized costs. They present only costs. They do not account for the full complement of DER benefits and they only account for the one benefit displayed along the horizontal axis, which in this case is GHG benefits. Therefore, while cost curves have some usefulness for comparing different DERs to each other, they should not be used in isolation for determining whether a DER is cost-effective. And while they can help inform prioritization across DERs, it may be important to also consider other comparisons that account for other differences in DER benefits.

D.6 Net Levelized Costs

D.6.1. Net Levelized Cost Calculations

As discussed above, levelized cost calculations divide the levelized measure or program cost of a DER by *just one* of the many benefits of each DER—whether kWh reduction, peak kW reduction, gas thermal reduction, GHG emissions reduction, or any other metric of interest. That limits the value and applicability of levelized costs calculations. For example, a DER that provides both energy savings and system peak demand savings may be more cost-effective (either greater net economic benefits and/or higher benefit-cost ratio) but look more expensive on a levelized cost per kW of system peak reduction basis than a different DER that provides only system peak kW benefits.

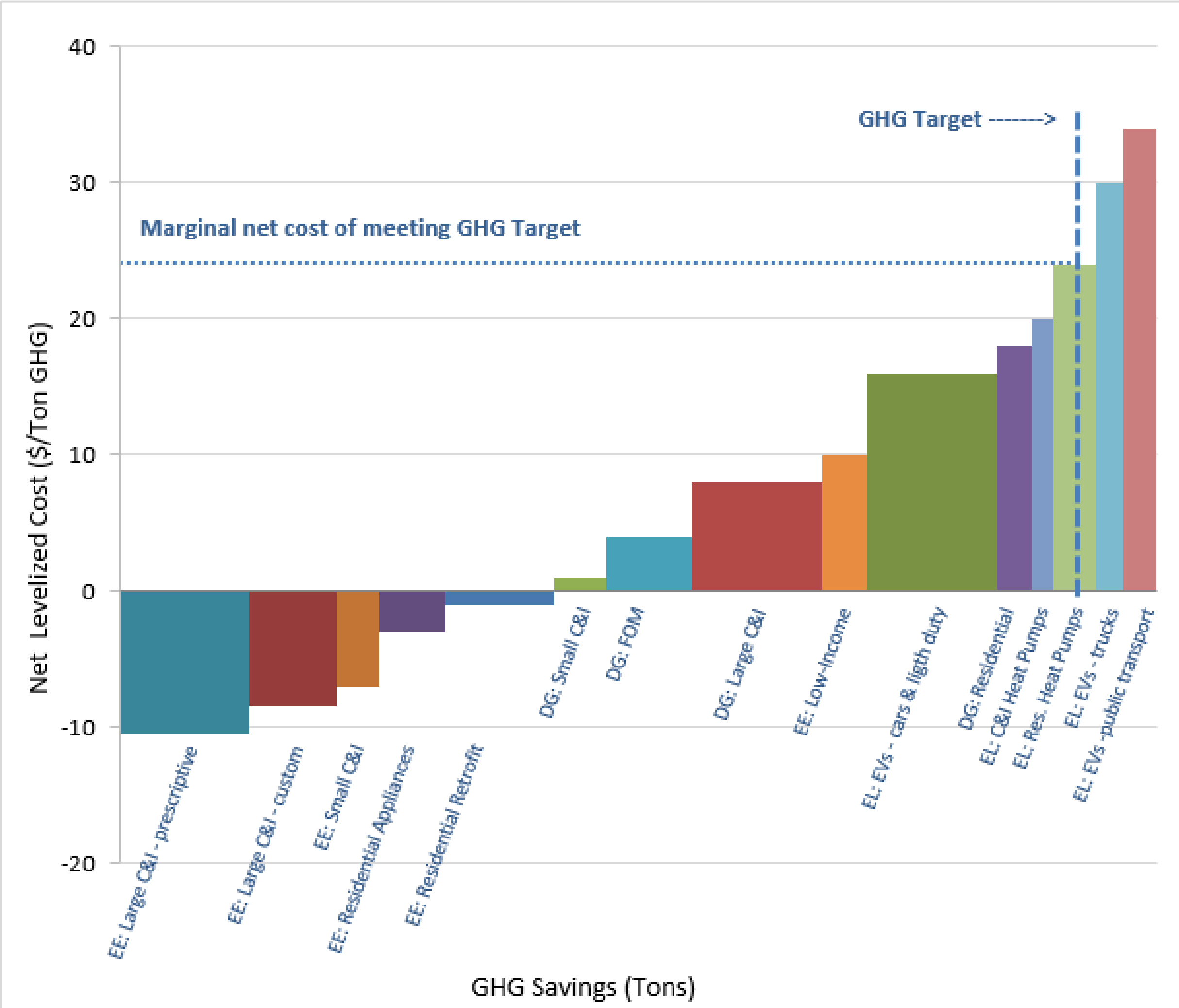
That limitation can be addressed through one important modification: subtracting the value of the "other benefits" (i.e. all benefits other than the one by which levelized costs are being divided) from the DER measure or program cost used in a standard levelized cost calculation. The result is a *net levelized cost*. As with levelized costs, net levelized costs can be computed for any DER impact or benefit of interest—whether kWh saved, system peak kW reduction, distribution kW reduction, gas thermal reduction, GHG emissions reduction, or any other metric.

D.6.2. Net Levelized Cost Curves

Net levelized cost curves present all the relevant benefits and costs, where one of the benefits is displayed along the horizontal axis and the net levelized costs are presented along the vertical axis. These are similar to the levelized cost curves discussed above except that net levelized costs are presented.

Figure D-7 presents an example of a net levelized cost curve for GHG reductions. It uses all the same information as the example in Figure D-6, except that all the benefits but GHG emission benefits are subtracted from the DER costs before they are levelized. The DERs whose net costs are negative in the figure represent those DERs that are cost-effective even without accounting for the value of avoided GHG emissions. The DERs whose net costs are positive represent those that are not cost-effective without accounting for the value of avoided GHG emissions but might be cost-effective once the value of such emission reductions is included in the BCA.

Figure D-7. Example of GHG Net Cost Curve: Hypothetical Set of Multiple DER Types



Net cost curves such as this one can be used for several purposes. For example:

- Net cost curves can be used to prioritize DERs according to those that will reduce GHG emissions at the lowest cost. The leftmost DERs can be prioritized over those on the right.
- Net cost curves can be used to determine which are the lowest-cost DERs available to meet a particular GHG target. Figure D-7 includes a dashed vertical line indicating the hypothetical GHG emission reduction target for this hypothetical jurisdiction. The DERs to the left of that line represent the lowest cost options for meeting this GHG target.
- Net cost curves can be used to identify the marginal net cost of complying with a specific target. Figure D-7 includes a dotted horizontal line that indicates the marginal resource needed to meet the GHG target for this hypothetical jurisdiction. In this example, the marginal resource is EV initiatives for public transportation. As indicated in the previous figure, the cost of this DER is roughly 80 $/ton GHG. This marginal cost could be used as an input to the BCA; where the value in $/tons is used as the cost of achieving the jurisdiction's GHG target.
- Net cost curves can also be used to estimate how much of a resource is cost-effective for a given avoided cost value. For example, at a GHG emission reduction value of $50/ton, all the

resources to the left of the C&I heat pumps program in Figure D-7 are cost-effective. Similar assessments can be used, for example, in comparing non-wires solutions—when their costs are expressed in net levelized cost per distribution kW—to the cost of a substation or other traditional T&D capacity upgrade and/or the value of deferring such an upgrade.

Levelized cost and net cost curves help allow for a clear comparison and ranking across DERs and DER types. The information regarding the amount of savings available from each DER is useful for determining how they meet a jurisdiction's DER goals, relative to each other. This information can be especially useful for jurisdictions seeking to develop portfolios of multiple DER types across a utility service territory, as discussed in Chapter 13.

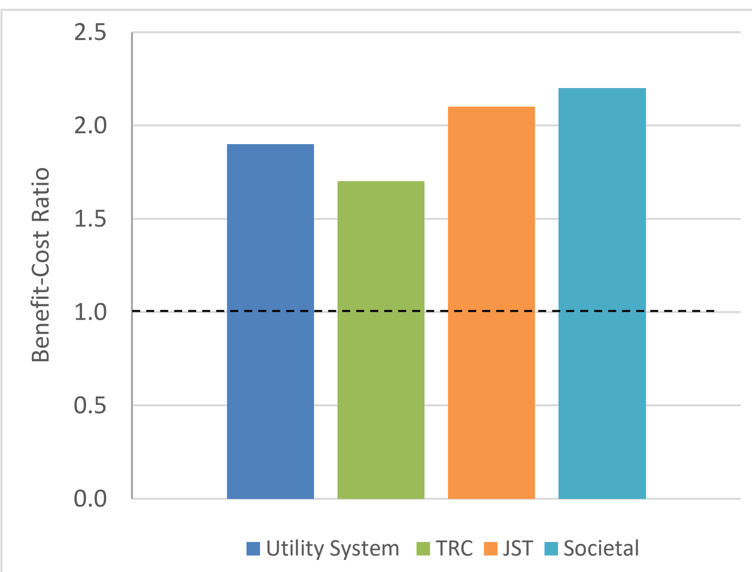
D.7 Multiple Cost-Effectiveness Tests

D.7.1. Multiple Tests for One DER Type

Some jurisdictions might choose to use secondary tests, as described in Section 3.5. In some cases, it might be helpful to present more than one secondary test. Different tests provide different information, and there may be situations where that additional information is helpful in analyzing and deciding among DER options.

Figure D-8 presents an example of how multiple test results can be used to provide additional information about DER benefits and costs. It shows the BCA results for a hypothetical EE portfolio in terms of benefit-cost ratios, for a hypothetical JST as well as the traditional UCT, TRC, and SCT. Presenting the results this way allows for a quick assessment of how cost-effective this DER is according to different tests.

Figure D-8. Presentation of Multiple BCA Tests: Benefit-Cost Ratios—Hypothetical EE Portfolio



The primary test (JST) used in this example is assumed to include the following impacts: utility system, host customer, other fuel, low-income, and GHG emissions.

For this hypothetical EE portfolio:

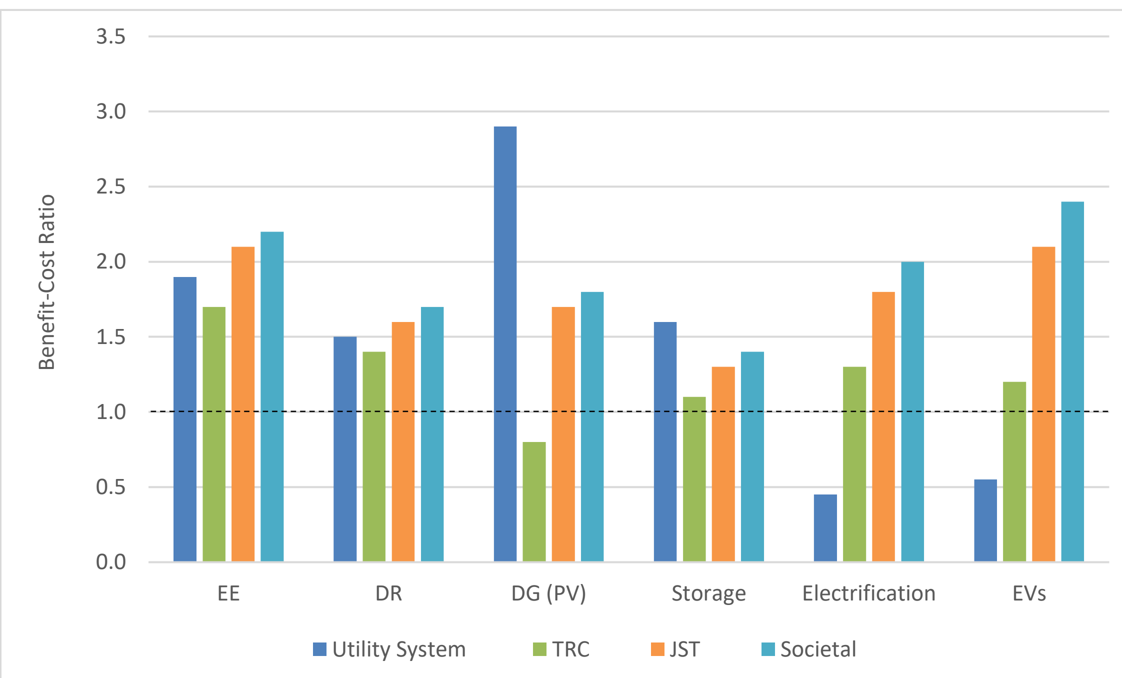
- UCT results: The EE is very cost-effective, and the utility system benefits exceed the utility system costs by a factor of two.
- TRC results: The EE is less cost-effective than under the UCT because the TRC Test includes host customer impacts, which are predominantly costs in this example. The TRC also includes low-income impacts and other fuel impacts.
- JST results: The EE is more cost-effective than under the UCT because the JST includes low-income benefits, other fuel impacts, and GHG benefits—it is more cost-effective than the TRC because it includes GHG benefits.
- SCT results: The EE is more cost-effective than under the JST because the SCT includes other environmental, public health, economic development, and energy security benefits.

D.7.2. Multiple Tests and Multiple DER Types

Some BCA practitioners might choose to use secondary tests and apply them across multiple DER types. Again, different tests provide different information, and there may be situations where that additional information is helpful in analyzing and deciding among DER options.

Figure D-9 presents the BCA results for hypothetical DERs in terms of benefit-cost ratios. Presenting the results this way allows for a quick assessment of how cost-effective the different DER types are according to different tests.

Figure D-9. Presentation of Multiple BCA Tests: Benefit-Cost Ratios—Multiple DER Types



This example uses the same primary test used in the previous sub-section. The primary test is assumed to include the following impacts: utility system, host customer, other fuel, low-income, and GHG emissions.

For this hypothetical EE scenario:

- The results are the same as those presented and explained in the previous section.

For this hypothetical DR scenario:

- UCT results: The DR is reasonably cost-effective—the utility system benefits exceed the utility system costs by a factor of 1.5.
- TRC results: The DR is slightly less cost-effective than under the UCT because the TRC results include some small net costs to the host customer.
- JST results: The DR is slightly more cost-effective than under the UCT because the JST includes low-income and GHG benefits.
- SCT results: The DR is slightly more cost-effective than under the JST because the SCT includes other environmental, public health, economic development, and energy security impacts.

For this hypothetical PV scenario:

- UCT results: The PV is very cost-effective—the utility system benefits exceed the utility system costs by a factor of three. This is because the utility costs are relatively low since most PV costs are borne by the host customer.
- TRC results: The PV is much less cost-effective than under the UCT because the TRC Test includes host customer impacts that are predominantly costs and the host customer costs cover the majority of PV costs.
- JST results: The PV is the more cost-effective than under the TRC Test because the JST includes GHG benefits.
- SCT results: The PV is less cost-effective than under the UCT because the SCT includes host customer costs. It is more cost-effective than under the JST test because the SCT includes other environmental, public health, economic development, and energy security impacts.

For this hypothetical storage scenario:

- UCT results: The storage is reasonably cost-effective—the utility system benefits exceed the utility system costs by a factor of 1.6.
- TRC results: The storage is much less cost-effective than under the UCT because the TRC Test includes host customer impacts, which are predominantly costs in this case.
- JST results: The storage is less cost-effective than under the UCT because the JST includes host customer costs and the storage resource causes a slight increase in GHG emissions because it creates a net increase in electricity generation.
- SCT results: The storage is less cost-effective than under the UCT because the SCT includes host customer costs. It is more cost-effective than under the JST test because the SCT includes other environmental, public health, economic development, and energy security impacts.

For this hypothetical electrification scenario:

- UCT results: The electrification is not cost-effective—with a benefit-cost ratio of 0.9. This occurs because this test does not account for the other fuel savings, which are the primary rationale for the electrification.
- TRC results: The electrification is more cost-effective than the UCT because the TRC Test accounts for the other fuel savings.
- JST results: The electrification is more cost-effective than under the TRC Test because the JST includes GHG emission impacts.
- SCT results: The electrification is more cost-effective than under the JST because the SCT also includes other environmental, public health, economic development, and energy security impacts.

For this hypothetical EV scenario:

- UCT results: The EV is not cost-effective—with a benefit-cost ratio of 0.8. This occurs because this test does not account for the other fuel savings.
- TRC results: The EV is more cost-effective than the UCT because the TRC Test accounts for the other fuel savings.
- JST results: The EV is more cost-effective than under the TRC Test because the JST includes GHG emission impacts.
- SCT results: The EV is more cost-effective than under the JST because the SCT also includes other environmental, public health, economic development, and energy security impacts.

Appendix E. Traditional Cost-Effectiveness Tests

This appendix provides a description of the traditional tests used for assessing DER cost-effectiveness and is intended to provide the theoretical underpinnings of what should be included in the traditional tests, which sometimes differs from actual practice. Chapter 3 describes how use of the NSPM BCA Framework to develop a jurisdiction's primary test compares to these traditional tests. This appendix also emphasizes the distinction between cost-effectiveness analysis and rate impact analysis and refers to Appendix A for more detailed information and guidance on rate impact analyses.

E.1 Overview

This appendix provides information on the five traditional screening tests: the Utility Cost Test, (also known as the Program Administrator Cost Test); the Total Resource Cost Test; the Societal Cost Test; the Participant Cost Test; and the Rate Impact Measure Test. These traditional tests are presented in the *California Standard Practice Manual* and have been used to assess cost-effectiveness for efficiency resources for several decades.[72]

As discussed in both the introduction to this manual and in Chapter 3, a jurisdiction using the NSPM BCA Framework could develop a primary cost-effectiveness test that fully aligns with one of these traditional tests, or that it is unique to the jurisdiction, depending on the outcome of applying the principles set forth in Chapter 2 to the specific jurisdiction. This appendix describes the key elements of these traditional tests.

For each of the traditional tests, this appendix provides:

- A description of the test;
- The relevance of the test for cost-effectiveness assessment;
- The benefits and costs covered under each test; and
- Limitations of each test.

Table E-1 provides a conceptual overview of the traditional cost-effectiveness tests. Table E-2 provides a summary of the various benefits and costs that, to be consistent with the analytical perspective each test is intended to represent, should be included in these tests. Additional information on each test is provided in the sections that follow.

[72] While most jurisdictions have historically used the CaSPM as the foundation for their cost-effectiveness tests, in practice many jurisdictions have deviated from those tests and developed modified versions.

Table E-1. Conceptual Overview of the Traditional Cost-Effectiveness Tests

Test	Perspective	Key Question Answered	Impacts Accounted For
Utility Cost	The utility system	Will utility system costs be reduced?	Includes the benefits and costs experienced by the utility system
Total Resource Cost	The utility system plus participating customers	Will utility system costs plus program participants' costs be reduced?	Includes the benefits and costs experienced by the utility system, plus benefits and costs to program participants
Societal Cost	Society as a whole	Will total costs to society be reduced?	Includes the benefits and costs experienced by society as a whole
Participant Cost	Customers who participate in a program	Will program participants' costs be reduced?	Includes the benefits and costs experienced by the customers who participate in the program
Rate Impact Measure	Impact on rates paid by all customers	Will utility rates be reduced?	Includes the benefits and costs that will affect utility rates, including utility system benefits and costs plus lost revenues

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

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

In the case of the PCT and the RIM Test, while these are traditionally referred to as cost-effectiveness tests, they should not be used to answer the key question of which DERs should be funded or otherwise supported by utilities on behalf of customers. Instead, the PCT should be used to assist with program design and estimating customer participation, and the RIM Test should be used (a) to determine whether rates are likely to increase or decrease, and (b) to determine whether to conduct a rate, bill, and participation analysis.

Each of these tests are discussed in turn below.

E.2 Utility Cost Test

Description: The purpose of the UCT is to indicate whether the benefits of a DER resource will exceed its costs from the perspective of only the utility system.[73] The UCT includes all benefits and costs that affect the operation of the utility system and the provision of electric and gas services to customers. For vertically integrated utilities, this test includes all of the benefits and costs that affect utility revenue requirements. For utilities that are not vertically integrated, this test includes all benefits and costs that affect utility revenue requirements, plus additional benefits and costs associated with market-based procurement of electricity and gas services.

Costs Included: The UCT should account for all utility system costs that are incurred to implement the DER resource.

Benefits Included: The UCT should account for all utility system costs that are avoided by the DER resource.

Relevance to DER Assessment: The UCT is useful for identifying the impact of a DER on utility-system costs and average customer bills, and thus is consistent with the principle that DERs are a resource. It is also useful for identifying the extent to which utility investments will provide reduced costs to that same overall group of utility customers, and therefore can have value (among other factors) for informing decisions on relative program priorities, program design (e.g., customer incentive levels) and/or limits on program spending. As discussed in Chapter 3 the UCT should serve as the foundation upon which a jurisdiction's DER assessment test is built. From this foundation, other relevant impacts should be added to align the test with the jurisdiction's applicable policy goals.

E.3 Total Resource Cost Test

Description: One of the key principles of cost-effectiveness assessment is that utility DER investments should be evaluated as a resource and compared with other demand-side and supply-side resources. The TRC does so from the combined perspective of the utility system and participants. Thus, this test includes all impacts of the UCT, plus all impacts on the program participants.

Costs Included: The TRC Test should account for all utility system and program participant costs incurred to implement the DER resource.

Benefits Included: The TRC Test should account for the utility system and program participant benefits that are experienced because of the DER resource.

Relevance to DER Resource Assessment: The TRC Test provides more comprehensive information than the UCT by including the impacts on participating customers. As a result, this test includes impacts on other fuels, which allows for a comprehensive assessment of multi-fuel programs and fuel-switching programs. This test also conceptually includes other non-energy impacts on participants. This is particularly important for low-income programs.

[73] The UCT is sometimes referred to as the Program Administrator Cost test in the case of BCA of ratepayer-funded energy efficiency programs where programs are implemented by non-utility administrators. The UCT is a more accurate name because the benefits and costs included in this test are those that affect the utility system, not those that affect the Program Administrator.

E.4 Societal Cost Test

Description: The purpose of the SCT is to indicate whether the benefits of a DER resource will exceed its costs from the perspective of society as a whole. This test provides the most comprehensive picture of the total impacts of a DER resource. This test includes all the impacts of the TRC Test, plus the additional impacts on society. The CaSPM refers to the SCT as a "variation" of the TRC Test (CPUC 2001). Since then, many jurisdictions and many studies have referred to the SCT as a separate test with different implications.

Costs Included: The SCT should account for all costs that are incurred to acquire the DER resource, including all utility system and all non-utility system costs.

Benefits Included: The SCT should account for all of the benefits that result from the DER resource, including all utility system and all non-utility system benefits.

Relevance to DER Resource Assessment: The SCT is useful for identifying the full range of economic impacts on society resulting from the investment in DER resources. It is particularly apt for jurisdictions that have particular interest in a range of societal considerations, such as environmental or economic development concerns, in addition to an interest in minimizing utility system and efficiency program participant costs.

E.5 Participant Cost Test

Description: The intended purpose of this test is to indicate whether the benefits of a DER program will exceed its costs from the perspective of the DER program participant. This test includes all impacts on the program participants, but no other impacts.

Costs Included: The PCT should account for all costs that are incurred by the host customer to install, operate, and maintain the DER, including direct costs and non-energy costs.

Benefits Included: The PCT should account for all benefits experienced by the host customer, including bill savings and non-energy benefits. This test should not include avoided utility system costs as a benefit.

Relevance to DER Resource Assessment: The PCT is not appropriate for assessing the value of DER as a utility system resource because, unlike the other four tests described here, it values benefits based on avoided electricity and gas *rates* rather than on avoided utility system *costs*. That violates the *Conduct Forward-Looking, Long-term, Incremental Analyses* principle, which states that cost-effectiveness analysis should be forward-looking, because electric and gas rates are designed to recover both variable (avoidable) costs and fixed (unavoidable) costs, some of which were incurred in the past. An example would be the cost of previous capital investments in the T&D system or generating capacity in vertically integrated utilities.[74]

That said, the PCT can have value for the purpose of informing program design (e.g., the level of financial incentives to offer prospective participants and/or the need for marketing to better inform

[74] They may be "avoided" in part by participants, but typically only if a larger portion is then recovered by non-participants. Put another way, a portion of participant benefits is often just a shift in costs from one customer group (participants) to another (non-participants) rather than a true cost savings.

participants of non-energy benefits that they may value) by providing insight into energy bill impact on participants.[75]

E.6 Rate Impact Measure Test

Description: The purpose of this test is to indicate whether a DER resource will increase or decrease electricity or gas rates (i.e., prices). This test includes all of the benefits and costs of the UCT, plus estimates of the utility lost revenues created by DER programs. When regulators take steps to allow utilities to recover the lost revenues of DER programs, through rate cases, revenue decoupling, or other means, then the recovery of these lost revenues will create upward pressure on rates. If this upward pressure on rates exceeds the downward pressure from reduced utility system costs, then rates will increase, and *vice versa*.

Costs Included: The RIM Test should account for all utility system costs that are incurred to implement the DER resource. It should also include lost revenues as a cost. The lost revenues are equal to the host customer bill savings.

Benefits Included: The RIM Test should account for all utility system costs that are avoided by the DER resource.

Relevance to DER Resource Assessment: As provided by the NSPM principles in Chapter 2, and further explained in Appendix A, the RIM Test is designed to address rate impacts and therefore answers fundamentally different questions than does a cost-effectiveness analysis. As such, the RIM Test is limited in determining which DERs are cost-effective—i.e., have benefits that exceed their costs and therefore warrant utility acquisition on behalf of utility customers. This is because the RIM Test does not measure changes in net economic costs across a population; rather, it is a measure of distribution equity. Even in that context, the RIM Test considers only one of the three factors that regulators should consider when exploring distributional equity concerns. It does not consider bill impacts or participation rates, which are critical for understanding distributional equity.

Table E-3 summarizes the purpose of each of the traditional tests, and the relevance to DER assessment.

[75] The U.S. Department of Energy uses a different test to determine whether to include efficiency measures to participants in federally funded weatherization assistance programs. It uses the savings-to-investment ratio; where the numerator is the present value of net savings in energy, water, non-fuel, or non-water operation and maintenance costs attributable to the proposed energy or water conservation measure, and the denominator is the present value of the cost of the proposed energy or water conservation measure.

Table E-3. Summary of the Traditional Cost-Effectiveness Tests

Test	Purpose	Relevance to DER Assessment
Utility Cost	Indicates the extent to which ratepayer-funded resources will reduce costs to that same group of ratepayers; provides a foundation for all resource assessment tests	Indicates the impact of the resource on utility system cost and average customer bills
Total Resource Cost	Provides a more comprehensive view of DER impacts than the UCT, including impacts of other fuels, which is helpful for multi-fuel programs, and impacts on DER program participants (if properly applied with symmetrical treatment of benefits and costs)	Indicates the total cost of a resource, regardless of who pays for it
Societal Cost	Most comprehensive test, enabling an assessment of cost-effectiveness based on the universe of benefits and costs of the resource investment	Indicates the full impact of a resource on society
Participant Cost	Useful in program design, to inform appropriate participant incentives	Not relevant for cost-effectiveness testing
Rate Impact Measure	Indicates whether long-term rates will increase or decrease on average	Not appropriate for cost-effectiveness assessment

Appendix F. Transfer Payments and Offsetting Impacts

This appendix provides guidance on how to identify whether certain benefits and costs offset each other and should therefore be excluded from the BCA.

F.1 Summary of Key Points

- The term "transfer payment" is used in economics to refer to a one-way payment of money for which no money, good, or service is received in exchange. Typical examples include government payments for programs such as Social Security, Medicare, and unemployment.
- The term "transfer payment" is sometimes used in the context of DER BCAs to refer to a situation where a cost to one party is exactly offset by a corresponding benefit to another party. This raises the question of whether transfer payments should be excluded in the BCA because they cancel each other out.
- In many cases, the transfer payments identified in DER BCAs are not the same thing as transfer payments as defined by economic theory (i.e., they are not a one-way payment of money for which no money, good, or service is received in exchange) and they are not driven by government programs.
- There are some situations in DER BCAs where a DER cost experienced by one party is exactly offset by a corresponding DER benefit experienced by another party. This manual refers to these situations as "offsetting impacts," in order to avoid confusion with transfer payments as defined by economic theory.
- Offsetting impacts in DER BCAs can be identified by considering two criteria. If both of these criteria are met, then the benefits and costs in question are offsetting impacts:
    - The cost in question is not a part of the total cost of the DER and is not a part of the costs avoided by the DER.
    - Both the party incurring the cost and the party receiving the benefit are within the scope of the cost-effectiveness test being used.
- Table F-1 presents a summary of the DER impacts that are sometimes considered transfer payments. A "no" entry indicates that the impact is not an offsetting impact, while a "yes" entry indicates that the impact is an offsetting impact.

Table F-1. Potential Offsetting Impacts

BCA Test Used	Financial Incentives to Host Customers	DER Performance Incentives	Wholesale Market Price Effects	Tax Incentives
Utility Cost Test	No	No	No	Not Relevant
TRC Test	Yes	No	No	No
Jurisdiction-Specific Test	Depends	No	No	Depends
Societal Cost Test	Yes	No	No	Yes

F.2 Introduction and Terminology

> In this manual, the term "off-setting impacts" is used to refer to the situation where a DER cost (or benefit) experienced by one party is exactly offset by a corresponding DER benefit (or cost) experienced by another party and it is appropriate to exclude both impacts from the BCA.

Some DER BCA studies use the term "transfer payment" to describe this situation where one party experiences a cost and another a commensurate benefit (CA PUC 2001). This term has a specific meaning in economics, and is defined as follows:

> A transfer payment is a one-way payment of money for which no money, good, or service is received in exchange. Transfer payments commonly refer to efforts by local, state, and federal governments to redistribute money to those in need. Typical examples of transfer payments include government programs such as Social Security, Medicare, student grants, and unemployment compensation.[76]

In many cases, the transfer payments identified in DER BCAs are not the same thing as transfer payments as defined by economic theory. They are not a one-way payment of money for which no money, good, or service is received in exchange, and they are not driven by government social service programs.

Nonetheless, there are some situations in DER BCAs where a DER cost experienced by one party is exactly offset by a corresponding DER benefit experienced by another party. In some situations, it may be appropriate to exclude both impacts from a BCA because the net impact is zero, but in other cases it may not be appropriate to exclude both impacts because the two impacts do not truly offset each other.

In this manual, the term "off-setting impacts" is used to refer to the situation where a DER cost (or benefit) experienced by one party is exactly offset by a corresponding DER benefit (or cost) experienced by another party and it is appropriate to exclude both impacts from the BCA. The term "transfer payments" is not used further in this manual, in order to avoid confusion with the economic definition of that term.

The following section describes two criteria for determining when it is appropriate to treat two impacts as offsetting impacts and when it is not. The sections after that discuss several examples of impacts that are sometimes considered offsetting impacts and provide guidance on how to determine whether they should be included or excluded in a BCA test.

F.3 Criteria for Identifying Offsetting Impacts

There are several factors that determine whether two impacts offset each other and should therefore be excluded from the BCA test. These include the nature of the impact and the scope of the cost-effectiveness test being used. These two criteria can be used to determine whether two impacts are offsetting impacts:

- The cost in question is not a part of the total cost of the DER and is not a part of the costs of the resources avoided by the DER.
- Both the party incurring the cost and the party receiving the benefit are within the scope of the BCA test. If both parties are not within the scope of the test, then the cost and the benefit will

[76] http://www.businessdictionary.com/definition/transfer-payment.html.

not offset each other. Determining whether this is the case requires answering the following questions:

- What categories of impacts are included the jurisdiction's primary cost-effectiveness test?
- Which party is incurring the cost? Are impacts on that party among the categories of impacts included in the jurisdiction's primary test?
- Which party is receiving the benefit? Are impacts on that party among the categories of impacts included in the jurisdiction's primary test?

Any set of benefits and offsetting costs should be assessed using these two criteria in order to determine whether they should be treated as offsetting impacts in BCA. A set of benefits and costs must meet both criteria in order to be treated as offsetting impacts.

Offsetting impacts should not be included in the BCA test because the benefit offsets the cost. Impacts that are not an offsetting impact should be included in the BCA test because the benefit does not offset the cost.

F.4 Financial Incentives to Implement DERs

Utilities and other DER program administrators offer rebates or other financial inducements to participate in DER programs. Common examples include incentives for efficiency measures or for agreements to participate in DR programs. (See Chapter 4.)

The cost of a financial incentive is experienced by all customers that pay for the DER program. The benefit of a financial incentive is experienced by the DER host customer.

Table F-2 applies the criteria described above to determine whether financial incentives are an offsetting impact. As indicated in the table, financial incentives are not offsetting impacts in the UCT but are in tests that include host customer impacts:

- Under the UTC, financial incentives are not an offsetting impact because one of the parties (host customers) are not a part of the test. In this case, financial incentives should be included in the test as one of the costs of the DER.
- Under cost-effectiveness tests that include host customers, financial incentives are an offsetting impact because they are not a part of the total cost of the DER. Instead, they are an exchange between two parties to help host customers overcome the market barriers to the DER. In this case, financial incentives should not be included in the test. Instead, the DER cost (including costs to both the utility and host customers) should be included in the test.

Table F-2. Financial Incentives to Participate in DER programs

Criterion	Answer	Criterion Met?	Analysis and Implication
1. Is the cost a part of the total cost of acquiring the DER? Is the cost a part of the costs avoided by the DER?	No	Yes	Incentives to induce customers to install DERs are not a part of the costs to acquire DERs. Instead, they are a one-way payment to help host customers overcome market barriers to DERs.
2. Are both the party incurring the cost and the party receiving the benefit within the scope of the cost-effectiveness test?	Depends on the test used	Depends on the test used	Party Incurring Cost**:** Financial incentives to participate in DER programs are a utility system cost. All cost-effectiveness tests must include all utility system costs. Thus, the party incurring this cost is always within the scope of the test. Party Receiving Benefit**:** Host customers are typically the recipients of financial incentives. Their impacts are included in some tests but not all.
Conclusions: Utility Cost Test: The financial incentive is not an offsetting impact because the party receiving the benefit is outside the scope of the test. Tests that include host customer impacts: The financial incentive is an offsetting impact, where the cost of the incentive is offset by the benefit to the host customer.			
Implications: Utility Cost Test: The financial incentive should be included in the BCA test as a utility system cost. Tests that include host customer impacts: The financial incentive should be included in the BCA test as a utility system cost. The host customer impacts should include only the portion of the measure cost paid by the host customer.			

F.5 DER Performance Incentives

Some utilities or DER program administrators are eligible to receive performance incentives for the successful implementation of DERs. The most common example is when electric and gas utilities are subject to performance incentive mechanisms for EE programs. Other more recent examples include performance incentive mechanisms to support DG resources, NWSs, or EV infrastructure investments. (See Chapter 4.)

The costs of performance incentives are experienced by all customers that pay for the DER program. The benefits of performance incentives are experienced by the utility or DER program administrator.

Table F-3 applies the two criteria to determine whether performance incentives are an offsetting impact. As indicated in the table, performance incentives are not offsetting impacts because they are part of the total cost of implementing the DER. Financial incentives are equivalent to profits, which are commonly included as a cost associated with energy resources, as well as other types projects subject to a BCA.

This conclusion applies to all cost-effectiveness tests, because the parties experiencing the costs (all customers) and the parties experiencing the benefits (utilities or program administrators) are within the utility system and therefore should be included in all cost-effectiveness tests. (See Chapter 2.)

Table F-3. DER Performance Incentives

Criterion	Answer	Criterion Met?	Analysis and Implication
1. Is the cost a part of the total cost of acquiring the DER? Is the cost a part of the costs avoided by the DER?	Yes	No	DER performance incentives are a form of profit paid for the acquisition of DERs. Profits are part of the cost of acquiring DERs and other energy resources. Thus, performance incentives do not meet this criterion and are not offsetting impacts.
2. Are both the party incurring the cost and the party receiving the benefit within the scope of the cost-effectiveness test?	Yes	Yes	*Party Incurring Cost:* The costs of DER performance incentives are paid by the customers within the utility system. All cost-effectiveness tests must include all utility system impacts. Thus, the party experiencing the cost is always within the scope of the test. *Party Receiving Benefit:* The recipients of DER performance incentives are also part of the utility system. All cost-effectiveness tests must include all utility system impacts. Thus, the party experiencing the benefit is always within the scope of the test.
Conclusion: *All tests:* DER performance incentives are not an offsetting impact because they are a part of the cost of the DER.			
Implication: *All tests:* DER performance incentives should always be included in BCA tests as utility system costs.			

F.6 Wholesale Market Price Effects

Investments in some DERs can cause wholesale energy and capacity market prices to decline as a result of reduced demand. This short-term reduction in market prices are typically relatively small but the impacts are felt by all customers buying from the market at the time of the effect, and therefore the total impact can be significant. Some DERs cause increases in energy and peak demand, which has the opposite effect of increasing market prices. (See Chapter 4.)

When DERs cause market prices to be reduced, the costs are experienced by all generators that are selling into the market at the time of the effect, and the benefits are experienced by all customers purchasing from the market at the time of the effect. Conversely, when DERs cause market prices to increase, the costs are experienced by all customers purchasing from the market at the time of the effect, and the benefits are experienced by all generators that are selling into the market at the time of the effect.

Table F-4 applies the two criteria described above to determine whether wholesale market prices effects are an offsetting impact. As indicated in the table, wholesale market price effects are not an offsetting impact because they are part of the cost of the resources avoided by the DERs.

Wholesale market price effects are essentially a reduction (or increase) in suppliers' profits. Profits are a part of the cost of acquiring energy resources and are commonly included in BCAs as a cost, without any offsetting effect on the parties that benefit from the profits. It would be inconsistent to consider changes to wholesale suppliers' profits as an offsetting impact, and therefore exclude them from the BCA, when the profits of other entities that provide energy resources are included in the BCA.

The wholesale market price effects are not an offsetting impact for any cost-effectiveness test, because the parties experiencing the benefits and costs are all within the utility system and all cost-effectiveness tests should include benefits and costs to the utility system. (See Chapter 4.)

Table F-4. Treatment of Wholesale Price Effects

Criterion	Answer	Criterion Met?	Analysis and Implication
1. Is the cost a part of the total cost of acquiring the DER? Is the cost a part of the costs avoided by the DER?	Yes	No	Reductions (or increases) in wholesale energy prices from DERs will lead to reduced (or increased) profits for the competitive electricity and gas suppliers. Profits are part of the costs of the resources avoided by the DER. Thus, they do not meet this criterion and are not an offsetting impact.
2. Are both the party incurring the cost and the party receiving the benefit within the scope of the cost-effectiveness test?	Yes	Yes	*Party Incurring Cost*:[77] Competitive electricity and gas suppliers who experience reductions in revenues and profits from this effect are part of the utility system. All cost-effectiveness tests must include all utility system costs. Thus, the party experiencing the cost is always within the scope of the test. *Party Receiving Benefit*: Market buyers who receive the benefits of lower prices are also part of the utility system. All cost-effectiveness tests must include all utility system costs. Thus, the party experiencing the benefit is always within the scope of the test.
Conclusion: *All tests*: Changes in wholesale market clearing prices are not an offsetting impact because the profits affected by these changes are part of the costs of acquiring the alternatives to the DER.			
Implication: *All tests*: Reductions in market clearing prices should be included in all BCA tests as utility system benefits. Increases in market clearing prices should be included in all BCA tests as utility system costs.			

In addition, it is useful to consider this issue in the context of the wholesale markets themselves. From the perspective of wholesale market goals, it does not make sense to exclude suppliers' profits from the benefits (or costs) of a DER, for several reasons:

- Wholesale electricity markets are established with the goal of reducing costs to customers. This is achieved by using competitive forces to make suppliers provide their products as efficiently as possible. One way to make suppliers more efficient is to create pressure for them to reduce profits. Therefore, it does not make sense to exclude the benefits of reduced supplier profits from the BCA when this is one of the goals of competitive wholesale markets.
- Another goal of competitive markets is to shift some of the risks of energy resources from customers to the suppliers who have a comparative advantage to manage and mitigate those risks. Shifting risks in this way is clearly a benefit of wholesale electricity markets. Therefore, it does not make sense to exclude this benefit from the BCA by assuming that the profits to suppliers are exactly offset by the costs borne by customers.
- The fundamental market mechanism of balancing demand and supply depends not only on a robust set of options to supply electricity but also the ability for demand to respond to the changes in supply. DERs provide benefits to wholesale markets by allowing for more flexibility in the demand for supplies, i.e., by providing a more dynamic demand curve. Therefore, it does not

[77] The discussion in this example focuses on cases in which market prices are lowered. However, the results of the same for DERs that may increase market clearing prices. In those cases, both the bearer of the costs (market buyers) and the recipients of the benefits (market sellers) are part of the utility system and therefore within the scope of all cost-effectiveness tests.

make sense to exclude this benefit from the BCA by excluding the effect of the more dynamic demand curve.

F.7 Tax Incentives

Some DERs are eligible for incentives in the form of reduced local, state, or federal taxes. Common examples include federal tax breaks for certain highly efficient EE measures and federal and state tax breaks for installing distributed solar technologies. (See Chapter 4.)

The cost of tax incentives is experienced by the taxpayers who ultimately supply the incentives, and the benefit is experienced by host customers.

Table F-5 applies the two criteria to determine whether tax incentives are an offsetting impact. As indicated in the table, tax incentives are offsetting impacts in some tests but not others. Tax incentives are not a part of the total cost of the DER. Instead, they are one-way payment from the government to individual consumers purchasing eligible DERs. Thus, they meet this criterion for being an offsetting impact.[78]

However, for a tax incentive to be an offsetting impact both parties experiencing the impacts must be a part of the cost-effectiveness test.

- *For the UCT:* Tax incentives are not offsetting impacts because host customers and taxpayers are not included in this test.
- *For the TRC Test:* Tax incentives are not offsetting impacts because the party incurring the cost (taxpayers) are outside the scope of this test.
- *For the SCT:* Tax incentives are an offsetting payment because the scope of this test typically includes all taxpayers and host customers.
- *For other tests that include host customer impacts:* Tax incentives are offsetting effects if the scope of the test includes taxpayers. The decision to include certain taxpayers in the BCA test might depend upon the jurisdiction. For example, a state regulator may determine that the state's JST should encompass only impacts on its state taxpayers—and therefore would treat local or state tax incentives as offsetting impacts, but federal tax incentives as benefits. Similarly, a municipal utility may consider local tax incentives to be within the scope of its JST, but state or federal incentives to be outside its scope. In that example, a local tax incentive would be treated as an offsetting impact, but a state or federal tax incentive would be treated as a benefit.

[78] Tax incentives are the only example discussed in this appendix that fits the economic definition of a transfer payment.

Table F-5. Treatment of Tax Incentives

Criterion	Answer	Criterion Met?	Analysis and Implication
1. Is the cost a part of the total cost of acquiring the DER? Is the cost a part of the costs avoided by the DER?	No	Yes	Tax incentives are not a part of the total cost of the DER. Instead, they are one-way payment from the government to individual consumers purchasing eligible DERs.
2. Are both the party incurring the cost and the party receiving the benefit within the scope of the cost-effectiveness test?	Depends on the test used	Depends on the test used	*Party Incurring Cost:* Taxpayers are the party incurring the cost. Whether they are within the scope of the cost-effectiveness test can depend on both whether the tax credit is local, state, or federal, as well as what impacts are included in the test. *Party Receiving Benefit:* Host customers are typically the recipients of tax incentives. Their impacts are included in some tests but not all.

Conclusion:

Utility Cost Test: Tax incentives are not relevant because host customers and taxpayers are not included in this test.

TRC Test: Tax incentives are not an offsetting impact because the party incurring the cost (taxpayers) are outside the scope of this test.

Societal Cost Test: Tax incentives are an offsetting payment because the scope of this test includes all taxpayers.

Participant Cost Test: Tax incentives are not offsetting impacts because the party incurring the cost (taxpayers) are outside the scope of this test.

Other tests that include host customer impacts: Tax incentives are offsetting effects if the scope of the test includes taxpayers.

Implications:

Utility Cost Test: Tax incentives should not be included as a benefit or a cost.

TRC Test: Tax incentives should be included as a benefit to the host customer.

Societal Cost Test: Tax incentives should not be included as a benefit or a cost.

Participant Cost Test: Tax incentives should be included as a benefit to the host customer.

Other tests that include host customer impacts: Tax incentives should not be included as a benefit or a cost, unless the federal, state, or local taxpayers are outside the scope of the test.

Appendix G. Discount Rates

This appendix provides guidance on how to determine a cost-effectiveness test discount rate that is consistent with the objective(s) of the cost-effectiveness analysis and the jurisdiction's applicable policy goals. The concepts described in this appendix are applicable to all DERs.

G.1 Summary

- 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.
- Different economic actors may have differing discount rates, based on their own time preferences. However, the same discount rate should be used for assessing and comparing different DERs in order to allow for direct comparisons across all resource types.
- There are three categories of discount rates typically considered for DER assessments: WACC, average customers' discount rate, and societal discount rate. A fourth option is some combination of these three categories.
- 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.
- The following steps can assist regulators in determining the discount rate for their cost-effectiveness test(s):
    - Articulate the jurisdiction's applicable policy goals.
    - Consider the relevance of a utility's WACC.
    - Consider the relevance of the average utility customer discount rate.
    - Consider the relevance of a societal discount rate.
    - Consider an alternative discount rate.
    - Consider risk implications.
    - Based on these considerations, determine a discount rate that best reflects the jurisdiction's regulatory perspective.

G.2 The Purpose of Discount Rates

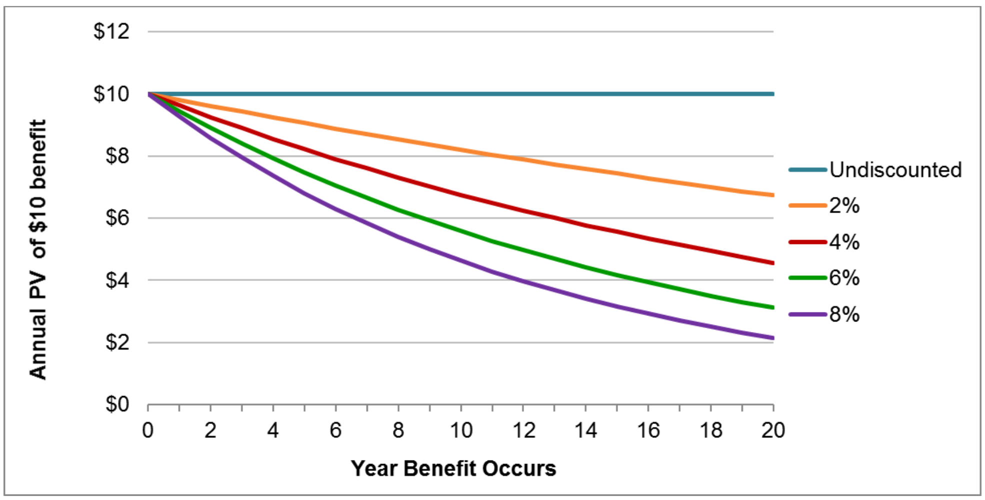
Discount rates are an essential aspect for assessing any multi-year project or investment. They allow analysts to compare benefits and costs that occur over different time periods.

Some utility costs, such as power plant siting, licensing, and construction, occur in the short term. Other utility costs such as fuel and O&M stretch into the long-term future. A power plant takes a few years to build, and then generates electricity for decades. On the other hand, many DER resources can be implemented within a year or two, and then operate for many years thereafter.

The key point is that dollars at different times in the future are not directly comparable values; they are apples and oranges. Applying discount rates turns benefits and costs in different years into comparable values. The choice of discount rates is a critical element of any long-term cost-effectiveness analysis because it has large impacts on the results. This is especially true when the analysis involves long-lived resources.

Figure G-1 illustrates how DER benefits (for instance, avoided generating fuel costs) can be affected by different discount rates. This example starts with an annual fuel costs savings of $10 per year over the course of a 20-year period. The top, blue line indicates the magnitude of the future avoided fuel costs assuming no discount rate. The other lines present the annual present value of the avoided fuel benefit, depending upon the discount rate used. As indicated, higher discount rates will dramatically reduce the value of avoided fuel savings benefits in Year 20, while lower discount rates have a much smaller impact.

Figure G-1. Implications of Discount Rates (annual present value dollars)



Note: These benefits are presented as real dollars (i.e., adjusted for inflation), and the discount rates are real discount rates.

G.3 Commonly Used Discount Rates

G.3.1. Different Perspectives and Time Preferences

As described earlier in this manual, the regulatory perspective is an important concept for determining a jurisdiction's primary cost-effectiveness test as well as the associated discount rate. The regulatory perspective includes the full scope of issues for which regulators and other relevant decision-makers are responsible. It is typically based upon statutes, regulations, executive orders, commission orders, and ongoing policy discussions.

However, the regulatory perspective can take into consideration other relevant perspectives, including:

> In some ways, the time preference from a regulatory perspective is aligned with utility customers' time preference. In both cases, time preference should be consistent with the objective of identifying those resources that will best serve customers. The time preference from the regulatory perspective, however, captures two additional considerations. First regulators have a responsibility to ensure that utility resources will meet applicable policy goals. Second, regulators have a responsibility to consider both current and future customer interests. For both of these reasons, the regulatory perspective should place a higher value on long-term benefits and costs than the utility customer perspective.

- *Investor-Owned Utility Perspective:* The utility WACC is typically used to indicate the time preference for investor-owned utilities (i.e., reflects the time preference of utility investors, based on the utility authorized return on equity, cost of debt, and debt-to-equity ratio). The key goal of utility investors is to maximize the returns on their investments. Therefore, the time preference of utility investors is not necessarily the same as the time preference of utility customers, or the regulatory time preference.
- *Publicly Owned Utility Perspective:* Publicly owned utilities, such as public power authorities, municipal utilities, and cooperatives, usually have a different time preference than investor-owned utilities. First, the cost of capital for publicly owned utilities is typically based solely on debt, and therefore is much lower than the WACC of investor-owned utilities. Second, publicly owned utilities' perspectives, by design, are likely to be more aligned with the time preference of utility customers as a whole.
- *Utility Customer Perspective:* An objective of utility cost-effectiveness analysis is to identify those resources that will best serve utility customers over the long term, while also achieving applicable policy goals of the jurisdiction. Thus, the utility customer time preference is an important consideration in determining the appropriate discount rate for analyses. There are at least two challenges to using customer-focused discount rates. First, the customers' cost of capital is only one factor that will influence the customers' time preference and thus they may place a different time preference on dollars spent on DERs relative to dollars spent on other products or other investments. Second, the customer cost of capital varies considerably across customer classes, and also across customers within classes. Any one cost-effectiveness test, however, can use only one discount rate. Therefore, to the extent that the customer cost of capital is used to inform the determination of a discount rate, it should be an average cost of capital that represents the broad range of utility customers.
- *Host Customer Perspective:* The host customers' perspective is directly relevant when applying the PCT because the goal of that test is to indicate the impact on host customers only. For this test, a discount rate reflecting the host customers' time preference would be appropriate.[79]

[79] The Participant Cost Test can be useful as a secondary test to provide useful information regarding the likelihood of customers adopting DERs, either on their own or with support from utility initiatives. This information can be helpful for designing DER initiatives, determining how much financial support to offer host DER customers, and forecasting future deployment of DERs.

Table G-1 summarizes several types of discount rates that could be used for energy resource cost-effectiveness assessment. For each type of discount rate, it indicates the time preference represented by that rate, a range of typical values, some brief notes, and sources.

Table G-1. Discount Rate Options for Cost-Effectiveness Analyses

Type of Discount Rate	Potential Indicator of Time Preference	Typical Values	Notes and Sources
Societal	Societal cost of capital, adjusted to consider intergenerational equity or other societal values	<0% to 3%	In addition to low-risk financing, government agencies have a responsibility to consider intergenerational equity, which suggests a lower discount rate (US OMB 2003). Society's values regarding environmental impacts might warrant the use of a negative discount rate (Dasgupta, Maler, and Barrett 2000).
Low-Risk	Interest rate on 10-year U.S. Treasury Bonds	-1.0% to 3%	Over the past 20 years the real interest rate on 10-year U.S. Treasury Bonds ranged between roughly -1.0% and 3.0% percent (multpl.com).
Utility Customers on Average	Customers' opportunity cost of money	varies	Customers' opportunity costs can be represented by either the cost of borrowing or the opportunity costs of alternative investments (Pindyck and Rubinfeld 2001, 550). The real rate on long-term government debt may provide a fair approximation of a discount rates for private consumption (US OMB 2003).
Publicly Owned Utility	Publicly owned utility's cost of borrowing	3% to 5%	Publicly owned utility costs of capital are available from the Federal Energy Regulatory Commission Form 1, Securities Exchange Commission 10k reports, and utility annual reports.
Investor-Owned Utility	Investor-owned utility's weighted average cost of capital	5% to 8%	Investor-owned utility costs of capital are available from the Federal Energy Regulatory Commission Form 1, Securities Exchange Commission 10k reports, and utility Annual Reports.

Note: Typical values of discount rates are in real terms, as opposed to nominal. Real interest rates take into account the effects of inflation whereas nominal rates have not been adjusted for inflation. Real discount rates should always be applied to real cash flows, and nominal discount rates should always be applied to nominal cash flows. The utility cost of capital should be after-tax.

The typical values presented in Table G-1 are provided for illustrative purposes only; other values outside these ranges are also possible. Other points to consider include that: these values can change over time according to changing economic conditions; there are multiple options for determining a low-risk discount rate; and different utility customers will have different time preferences, which can be determined in multiple ways.

Some practitioners recommend that the choice of discount rate should reflect the perspective represented by the cost-effectiveness test in use. For example, the U.S. Department of Energy and Environmental Protection Agency's National Action Plan on Energy Efficiency (NAPEE 2007, 5-4) states that:

- The societal discount rate should be applied when using the SCT.
- The utility weighted average cost of capital should be applied when using the UCT, the TRC Test, or the Rate Impact Measure (RIM) Test.
- A customer discount rate should be used when applying the PCT.

While there is some logic to the concept of matching the discount rate to the perspective of the test used, this logic must be applied carefully. First, it is important to recognize the role of the applicable policies in developing the cost-effectiveness test and in determining the appropriate time preference. Second, it is important to be clear on whose perspective is actually represented in particular discount rates.

G.3.2. Role of the Cost of Capital and Other Considerations

In general, the cost of capital is a key factor in determining discount rates. It indicates the time value of money (or the opportunity cost for alternative investments) for the relevant entity. However, cost of capital is not the only factor that dictates the appropriate discount rate to use for DER investments.

For example, the primary objective of a utility cost-effectiveness analysis is to identify those utility resources that will best serve customers over the long term, while also achieving applicable policy goals of the jurisdiction. In light of this objective, the time preference for cost-effectiveness analysis should account for more than just the cost of capital; it should also account for the value of utility service over the long term and applicable policy goals. In other words, important utility services (such as providing safe and reliable power) and important policy goals (such as protecting low-income customers or promoting economic development) are all factors that affect the time preference relevant to the cost-effectiveness analysis.

This point that a discount rate used for cost-effectiveness analysis could reflect more than just the cost of capital is at least one basis for the application of the societal discount rate. That rate, which is used in multiple applications, reflects more than simply the cost of capital to society. It also reflects societal values and priorities, such as long-term benefits to society, achieving societal goals, addressing the needs and interests of multiple entities across society, and more—some or all of which may be considerations included in a jurisdiction's policies.

G.4 Risk Considerations

Risk is often cited as an important factor to consider when determining a discount rate, because risk can affect the value that one might place on long-term versus short-term impacts. However, risk can be represented in different ways in a cost-effectiveness analysis, and it is important to be careful that any treatment of risk in the discount rate recognizes how risk is addressed in the rest of the analysis to ensure that there is no double-counting or under-counting of risk.

Risks can vary considerably across different types of utility resources. For example, EE resources tend to create relatively low risk; generators create different amounts of capital cost, siting, and construction risks; fossil-fueled generators create price escalation and volatility risks; and T&D facilities impose their own kinds of risks (Ceres 2012).

In general, it is preferable to account for such resource-specific risks separately and explicitly for each resource type, rather than embed it in a discount rate. Discount rates are applied to all resources in a cost-effectiveness analysis. Applying a single discount rate to all resources to reflect risks associated with any one of those resources, could conflate the treatment of resource-specific risk with the overall choice of time preference. Instead, resource-specific risk should be accounted for in developing the benefit cost and inputs to the cost-effectiveness analysis.

G.5 Determining the Discount Rate

Ultimately, the choice of discount rate is a decision regarding how much weight to give to long-term versus short-term benefits and costs. This decision should be driven by the regulatory perspective, and each jurisdiction should determine a discount rate based on its own policies and goals. Regulators/decision-makers can take the following steps to make this determination.

Step A: Articulate Policy Goals

Chapter 3 describes how regulators should identify and articulate policy goals. Those same policy goals should be articulated and applied when determining the discount rate.

Step B: Consider the Utility Investor Perspective

Regulators should consider whether the utility WACC represents the regulatory time preference. This decision can be based on answers to these questions: Is the utility investor time preference consistent with the jurisdiction's regulatory perspective and policy goals, is the utility investor time preference the appropriate time preference for resource planning, and does the utility WACC accurately reflect the cost of capital of DERs and the other resources being assessed? If the answer to any of these questions is "no," then alternative discount rates should be utilized, such as those based on customer or societal perspectives.

Step C: Consider the Average Customer Discount Rate

Regulators should consider whether the average customer discount rate represents the regulatory time preference. Should the discount rate be based on the average utility customer time preference? Does this time preference adequately address applicable policy goals and interests of future utility customers?

Step D: Consider the Societal Discount Rate

Regulators should also consider whether a societal discount rate is appropriate for the primary cost-effectiveness test, i.e., is a societal time preference consistent with the jurisdiction's applicable policy goals?

Step E: Consider an Alternative Discount Rate

Regulators should also consider whether to use a discount rate that is not tied to any one of the three perspectives described above. The regulatory perspective may be different from the perspective of utility investors, customers, and society. Thus, the regulatory time preference and discount rate could be different as well.

Step F: Consider Risk Implications

Resource-specific risk issues are best accounted for in estimating the costs of each resource, for example in the resource-specific cost of capital, as adjustments to a resource's benefits or costs, and/or in the avoided cost portfolio modeling process. Nonetheless, there may be situations where the DER benefits or costs do not properly reflect resource-specific risks. For example, the full set of risks associated with avoided costs (e.g., risks associated with avoided fuel costs, risks associated with construction costs) are sometimes not captured in the cost-effectiveness inputs.

In such situations, regulators and other decision-makers may choose to apply a discount rate to reflect the risk benefits (or risk costs) of DER resources, if those benefits or costs are not otherwise accounted for in the inputs to the analysis.

Step G: Determine a Discount Rate

Based on the considerations described above, regulators should determine a discount rate that best reflects the jurisdiction's regulatory perspective. Table G-2 offers suggestions for how this determination might be made.

Table G-2. Considerations for Determining a Discount Rate

Consideration	If the answer is "yes"
Time Preference Considerations:	
Does the regulatory perspective suggest the same time preference as utility investors?	Choose a discount rate equal to the utility WACC.
Does the regulatory perspective suggest placing a higher value on long-term impacts than utility investors?	Choose a discount rate less than the utility WACC.
Does the regulatory perspective suggest the same time preference as that of all utility customers?	Choose a discount rate that is represents all utility customers on average.
Does the regulatory perspective suggest the same time preference as that of society?	Choose a societal discount rate.
Does the regulatory perspective suggest placing a lower value on long-term impacts than society does?	Choose a discount rate greater than a societal discount rate, or at the high end of the range of societal discount rates.
Risk Considerations (for use in situations where resource-specific risks are not accounted for in the BCA inputs):	
Will DERs result in a net reduction in risk relative to alternatives?	Choose a relatively low-risk discount rate, such as the societal discount rate.
Will DERs result in a net increase in risk relative to alternatives?	Choose a relatively high discount rate.

Appendix H. Energy Efficiency: Additional Guidance

This appendix includes guidance on several detailed BCA issues not covered in Chapter 6 (Energy Efficiency Resources) of this manual but which were addressed in the 2017 NSPM for EE and which may still be useful for some jurisdictions.

These BCA issues or considerations are:

- H.1 Assessment Level;
- H.2 Analysis of Early Replacement (of functioning equipment);
- H.3 Free-Riders and Spillover.

H.1 Assessment Level

The cost-effectiveness of efficiency resources can be assessed at several levels of aggregation. Assessments can focus on individual measures, individual customer-specific projects, individual programs combining multiple measures and/or projects, sectors (e.g. all residential or all business programs), or portfolios of programs (across all sectors). This appendix discusses the advantages and disadvantages of conducting cost-effectiveness analyses at each of those levels. It also discusses the level at which fixed costs should be included in analyses.

Assessment level options include the following, and are each described in turn:

- Measure-level
- Project -level
- Program-level
- Sector-level
- Portfolio-level

H.1.1. Measure-Level Assessment

Resource assessment at the measure level means that each individual measure promoted by an efficiency program must be cost-effective on its own. Screening at the measure level is the most restrictive application of the cost-effectiveness tests.

Measure-level application of cost-effectiveness requirements will essentially guarantee that every measure included in an efficiency program will be cost-effective on its own. However, application of cost-effectiveness requirements at that level can have perverse implications. In some cases, it could reduce the overall net economic benefits of efficiency investments. That can occur for any of the following reasons:

- A customer’s interest in a non-cost-effective measure may be key to persuading the customer to install a package of measures that are cost-effective in aggregate. In such cases, the flexibility to promote the non-cost-effective measure as part of a package will lead to greater overall net benefits.

- A customer's interest in a non-cost-effective measure may be key to the development of a relationship with the customer that can lead to installation of cost-effective measures in the future. In that sense, promotion of the non-cost-effective measure can be analogous to a marketing investment.
- Installation of a non-cost-effective measure may be necessary in order to technically or safely enable the installation of other cost-effective measures. An example of this would be the installation of non-cost-effective mechanical ventilation in order to make indoor air quality acceptable when tightening up a building.

Another disadvantage of requiring all measures to be cost-effective is that it can be difficult to account for non-energy impacts, hard-to-monetize impacts, or additional considerations at the measure level. Some non-energy impacts, such as improved health and safety, are obtained through a package of multiple measures, and it is impractical to apply such impacts to each measure.

H.1.2. Project-Level Assessment

Resource assessment at the project level means that the combination of measures implemented together in a package for an individual customer must be cost-effective on its own. Project-level assessments are typically conducted only for projects undertaken by larger business customers for which the transaction cost of a site-specific assessment can be justified.

Project-level application of cost-effectiveness requirements will essentially guarantee that every project included in an efficiency program will be cost-effectiveness on its own. However, application of cost-effectiveness requirements at that level can have some (though fewer) of the perverse implications of measure-level cost-effectiveness requirements. Specifically, supporting the implementation of a non-cost-effective package of measures of interest to a customer can facilitate development of a relationship with customer that can produce a more cost-effective project later. Also, depending on whether and how participant non-energy benefits are included in cost-effectiveness assessments, the full value of non-energy benefits of a project may not be captured in project-level cost-effectiveness assessments.[80]

H.1.3. Program-Level Assessment

Resource assessment at the program level means that the measures and/or projects within a program must be cost-effective collectively. Some individual measures and/or projects may not be cost-effective on their own but could still be included in the program if the overall program were cost-effective.

The primary advantage of this approach is that it best represents the benefits and costs of initiatives that combine a set of actions (e.g., marketing, education, technical support, financial support, etc.) into

[80] The focus of this discussion is solely on the use of cost-effectiveness analysis to determine which investments merit acquisition from either utility system or broader perspectives. Efficiency programs targeted to large business customers often present benefits and costs to individual customers from the customer's perspective (i.e. using retail energy prices rather than avoided system costs, as well as considering customer non-energy benefits that may or may not be part of a jurisdiction's cost-effectiveness test). Similarly, some low-income programs base the determination of which measures to install on the savings-to-investment ratio (i.e., benefit-to-cost ratio) derived using the customer's retail rate. The merits of such customer-focused analyses are fundamentally different from those discussed here regarding utility system resource analyses.

a single package offered to customers. In addition, resource assessment at the program level avoids the problems noted above regarding missing the interrelationships between measures. These include technical connections and the ability to engage customers in ways that can lead to increasing net economic benefits, as well as the ability to properly capture customer non-energy benefits where warranted.

A disadvantage of this approach is that a program might include one or more measures that are not individually cost-effective and are not needed to account for the concerns addressed above. This has the effect of decreasing to some extent the overall cost-effectiveness of the program. However, this concern can be addressed with sound program design. Efficiency program planners and designers should include only those efficiency measures that effectively contribute to achieving the specific goals of the program.

One other potential concern with program-level screening is that it might preclude certain special programs that address important objectives at the sector or portfolio level. For example, pilot programs to test new and unproven program designs might not appear cost-effective but might provide future sector or portfolio benefits that cannot be identified in the present. For that reason, jurisdictions that apply program-level screening may want to allow these types of programs to be considered in a sector-level assessment.

H.1.4. Sector-Level Assessment

Resource assessment at the sector level means that the programs within a sector (e.g., low-income, residential, commercial and industrial)[81] must be cost-effective collectively. Some programs may not be cost-effective on their own but could still be implemented if the combined impact of all of the programs targeted to a given sector were cost-effective.

The primary advantage of this approach is that it indicates the benefits and costs of initiatives to provide a package of efficiency services to an entire sector. This may allow for non-cost-effective programs to be provided to a sector for the purpose of providing a complete set of efficiency services to that sector—an objective often driven by concerns about equitable access to efficiency programs across a large range and number of customers.

The primary disadvantage of this approach is that it could result in the inclusion of efficiency measures or programs that are not individually cost-effective, thereby decreasing the economic value of the suite of programs for that sector.

H.1.5. Portfolio-Level Assessment

Evaluation at the portfolio level means that the programs within a portfolio (i.e., combining all programs together) must be cost-effective collectively. Some programs may not be cost-effective on their own but could still be pursued if the combined impact of all of the programs was cost-effective.

[81] Some jurisdictions treat low-income programs as their own "sector," because of the special consideration often given to such customers in program design and delivery. Others treat low-income programs as part of the residential sector. Alternatively, though commercial and industrial customers could be considered to be different "sectors," most efficiency programs targeted to business customers do not differentiate between those two groups of customers, creating what are called business, non-residential, or commercial & industrial (C&I) sector programs. For the purpose of this manual, low-income, residential, and C&I are noted as three sectors of interest for illustrative purposes only. The conceptual discussion in this section applies regardless of whether low-income is treated as its own sector or as part of the residential sector and regardless of whether commercial and industrial are treated as their own sectors or combined.

The primary advantage of this approach is that it indicates the benefits and costs of the entire suite of EE programs.

The primary disadvantage of this approach is that it could result in implementing efficiency measures or programs that are not cost-effective, thereby decreasing the economic value of the overall portfolio.

H.1.6. Properly Accounting for Fixed and Variable Costs

A variety of costs are incurred in the acquisition of efficiency resources. It is important that those costs be included at the proper analytical level—e.g., measure, program, sector and/or portfolio—when analyzing the economics of efficiency resources. In a nutshell, only EE costs that are variable at a given analytical level should be included in cost-effectiveness analysis for that level because they are the only costs that can be avoided as a result of the analysis. EE costs that are largely fixed at a particular analytical level should not be "allocated" or otherwise included *at that level.* Doing so could lead to rejection of investments whose marginal benefits exceed their marginal costs, thereby lowering net economic benefits. That does not mean that EE costs that are fixed at a given analytical level should be omitted or ignored altogether. Instead, they can and should be included at higher level analyses at which they are variable and therefore are avoidable.

For example, when assessing the economics of efficiency measures, one should include only costs that largely increase or decrease in proportion to the number of measures installed. That will obviously include the cost of the measures themselves and could also include some program costs that are largely variable. Examples would include rebate processing costs, if the program administrator is paying a vendor a price for every rebate processed, and inspection costs if the program is committed to inspecting a certain percentage of all projects.[82] However, other EE program costs that are either largely fixed or do not change in proportion to program participation levels, such as the costs of marketing[83] or managing and evaluating the program, should not be included in the economic analysis of individual measures. Rather, they should be included only in a program-level cost-effectiveness assessment.

Similarly, portfolio costs that are either largely fixed or do not change in proportion to the number of programs or participation levels in those programs should not be allocated to programs for the purpose of analyzing the economics of individual programs. Rather, they should only be included at portfolio-level cost-effectiveness analysis. Such costs can include portfolio-level marketing, management, and evaluation costs.

The tables below illustrate the importance of accounting for largely fixed costs at the proper analytical level. Table H-1 shows that for each of five programs analyzed, the benefits exceed the variable costs of the programs. When largely fixed portfolio costs (equal to about 25 percent of the sum of the five program costs) are added to the sum of the variable impacts of the five programs, the portfolio itself is shown to be cost-effective, providing total net benefits of $800,000.

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[82] Alternatively, if the program is committed to inspecting enough projects to get a statistically valid sample, such that the number of inspections would not change significantly or at all between a level of 2000 and 10,000 participants, then such inspection costs should be treated as largely fixed and captured at the program level rather than at the measure level.

[83] Marketing costs can be somewhat variable in the sense that more marketing should lead to more participation. However, that relationship is rarely linear with the number of measures installed. In addition, and perhaps more importantly, program marketing budgets are often treated as largely fixed. That is, while marketing can play an important role in driving program participation, the costs of marketing do not go up and down as the number of participants goes up and down.

Table H-1. Proper Analysis with 25 Percent Fixed Portfolio Costs Included at Portfolio-Level Analysis

	Benefits ($000)	Costs ($000)	Net benefits ($000)	Positive net benefits?
Program 1	$500	$250	$250	Yes
Program 2	$300	$200	$100	Yes
Program 3	$1000	$400	$600	Yes
Program 4	$500	$300	$200	Yes
Program 5	$1000	$850	$150	Yes
Sum of all programs	$3300	$2000	$1300	Yes
Portfolio-level costs	$0	$500	-$500	
Total portfolio impacts	$3300	$2500	$800	Yes

Table H-2 shows that when the fixed portfolio-level costs are improperly allocated as 25 percent "adders" to each of the programs, the fifth program is no longer seen as cost-effective. If that program is then removed from the portfolio, but with portfolio costs remaining unchanged, the portfolio net benefits decline by $150,000 (i.e., the marginal impact of the fifth program on the portfolio) to $650,000.[84] In short, including fixed costs at the improper level can reduce the economic benefits of efficiency resource acquisition.

Table H-2. Improper Analysis with 25 Percent Fixed Portfolio Costs Allocated to Individual Programs

	Benefits ($000)	Costs ($000)	Net benefits ($000)	Positive net benefits?
Program 1	$500	$313	$188	yes
Program 2	$300	$250	$50	yes
Program 3	$1000	$500	$500	yes
Program 4	$500	$375	$125	yes
Program 5	$1000	$1063	-$63	no
Sum of all programs	$3300	$2500	$800	yes
Portfolio-level costs	Included as adder for each program			
Total portfolio if non-cost-effective programs excluded	$2300	$1650	$650	yes

H.2 Analysis of Early Replacement

Early replacement occurs when a functioning piece of equipment is replaced with a more efficient model before it normally would have been replaced. This section provides guidance on how to analyze the

84 Removing the fifth program would require a reallocation of the fixed portfolio cost to the remaining four programs (i.e. each of the remaining four programs would now be allocated a larger portion of the fixed portfolio costs). In this example, the four remaining programs would still all be cost-effective even after absorbing this larger allocation. However, under a different set of example programs, it is possible that the resulting larger allocation of fixed costs would render another program cost-ineffective.

benefits and costs of such early replacement efficiency measures. It also addresses why cost-effectiveness analysis of early replacement measures and programs requires special attention, as compared to other common measure categories.

Efficiency measures typically fall into one of four categories:

- *New Construction:* in which a building is going to be constructed, and an efficiency program prompts developers, builders, or contractors to install more efficient products or use more efficient construction practices than they otherwise would have.
- *Time-of-Sale/Natural Replacement:* in which a product is going to be sold and purchased, such as when an appliance breaks down and needs to be replaced, and an efficiency program is designed to persuade a vendor to sell and/or a customer to purchase a more efficient product than they otherwise would have.
- *Retrofit:* in which efficiency programs incentivize customers to install new efficiency measures in an existing space, such as an un-insulated attic.
- *Early Replacement:* in which an existing inefficient product is functioning and would not otherwise be replaced until a future year, and an efficiency program prompts a customer to replace it with a more efficient product sooner than he or she otherwise would have.

For the first three of those efficiency measure classifications, the cost impacts are commonly felt only in the first year (i.e., the incremental cost of an efficiency upgrade over a standard measure that would otherwise have been purchased or the full cost of a retrofit measure). The savings are thus simply the difference between the baseline efficiency and the new efficiency that will recur annually for the life of the measure.

Characterization of both the costs and savings of early replacement measures can be more complicated 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.

This section provides guidance on how to account for changes in the timing of costs, and accounting for multiple baselines for both costs and savings/benefits.

Accounting for Changes in the Timing of Costs

Under an early replacement scenario, there is the initial full cost of the replacement product. However, there are also potential cost savings from not having to buy the new product that would otherwise have been purchased several years into the future.

Consider, for example, the following hypothetical early replacement scenario:

- The customer has a 10-year-old and still functioning heating system with a 70 percent efficiency rating, and the heating system is normally assumed to last 15 years;
- *Absent an efficiency program influence*, the customer is expected to replace its 10-year-old heating system in five years with a new 90 percent efficient model that will cost $5,000;
- *With the efficiency program influence*, the customer decides to scrap its existing inefficient heating system and replace it today with a new 90 percent efficient model that costs $5,000.

In this case, there would be only five years of savings from the early replacement. If the cost-effectiveness test includes participant impacts, the net cost of the efficiency resource is equal to the $5000 initial cost of the early replacement *minus the NPV of the benefit of deferring a new purchase from the beginning of Year 6 to the beginning of Year 16*.[85] It is critically important that the reduction in cost associated with deferring the next new purchase be incorporated into cost-effectiveness analyses. To not account for it would result in markedly overstating the costs of early replacement measures and programs.[86]

Calculating the value of that deferral requires a cost amortization approach. This serves to align the mismatched timing of costs under the baseline condition and the early replacement condition, as illustrated in Table H-3.

In short, the amortizing or annualizing of the different purchase times under the baseline and early replacement scenarios has the effect of lining up costs so that the only difference is five years of annualized costs under the early replacement scenario. (The annualized cost under the baseline and early replacement scenarios are the same in Years 6 through 20, cancelling each other out.) Importantly, that also aligns the cost analysis with the benefits analysis (i.e., both benefits and costs occur only in Years 1 through 5).

Table H-3. Amortization to Address Mismatched Timing of Baseline and Early Replacement Costs

Costs		**Savings**	
Efficiency Measure Cost	$5000	Installed Measure Efficiency	90%
Standard New Product Cost	$5000	Standard New Product Efficiency	90%
Resource Life	15	Existing Efficiency	70%
Existing Product Remaining Life	5	Savings Annual Value (Years 1-5)	$600
Real Discount Rate	3%	Savings Annual Value (Years 6 and Beyond)	$0

Mismatched Timing of Costs Incurred under Baseline and Early Replacement Program Scenarios

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Baseline	-	-	-	-	-	$5000	-	-	-	-	-	-	-	-	-	-	-	-	-	$5000
Early Replace	$5000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$5000	-	-	-	$5000

Net Costs and Benefits of Early Retirement Calculated through Cost Amortization

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	NPV
Costs																					
Baseline	-	-	-	-	-	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$4313
Early Replace	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$6231
Net	$407	$407	$407	$407	$407	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$1918
Benefits	$600	$600	$600	$600	$600	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$2830
Net Benefits	$141	$141	$141	$141	$141	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$912
Benefit-Cost Ratio																					1.48

85 Year 6 is when the customer would otherwise have had to buy a new replacement heating system; Year 16 is when the customer will have to replace the new heating system that was just installed.

86 Again, this is only an issue if the cost-effectiveness test includes participant impacts. If it does not, the change in timing of costs associated with future equipment purchases is not relevant.

Accounting for Multiple Baselines for Both Costs and Savings

Unlike in the more straightforward example above, there can also be differences between the cost and efficiency of the early replacement measure that is installed today and the standard new product that would have otherwise been installed five years from now. For example, consider the following modifications to the hypothetical scenario outlined above:

- The customer has a 10-year-old and still functioning heating system with a 70 percent efficiency rating;
- This class of products is normally assumed to last 15 years, so absent an efficiency program influence, the customer is expected to replace its 10-year-old heating system in five years;
- The standard new heating system five years from now is expected to be an 85 percent efficient model that costs $4500;
- Within 10 years, the standard new heating system is expected to be a 90 percent efficient model that costs $5000;
- With the efficiency program influence, the customer opts to scrap its existing old inefficient heating system and replace it today with a new 90 percent efficient model that costs $5000. The new model is not only more efficient than the old heating system it is replacing, but also more efficient than the new heating system the customer would have bought five years from now.

In this case, as depicted in the bottom of

Table H-4, there would be five years of the same level of savings as assumed in the first hypothetical example depicted in Table H-3 (i.e., the difference between the old 70 percent and the new efficient 90 percent efficient model). However, unlike in the Table H-3 example, there would continue to be savings in Years 6 through 20, though the magnitude of those savings would be lower than in the first five years (i.e., the difference between a standard new 85 percent efficient model and an efficient new 90 percent efficient model). Thus, in the hypothetical example, the NPV of benefits is more than $1300 greater ($4140 vs. $2830) than in the Table H-3 example.

On the cost side of things, there would not only be a difference between no baseline cost and the amortized costs of the 90 percent efficient model for the first five years, but also a slightly higher amortized cost in the subsequent 15 years to reflect the difference in cost between a new 85 percent efficient model and a new 90 percent efficient model. Thus, in this hypothetical example, the NPV of costs is also greater—by over $400 ($2349 vs. $1918)—than in the Table H-3 example.

The net effect of these changes in benefits and costs is an increase in net benefits per measure of nearly $900 (i.e., $1791 vs. $912) relative to the net benefits of the Table H-3 example. It should be noted that the direction of this change is unique to this set of hypothetical assumptions. For example, if the cost of a new 85 percent efficient model in Year 6 was assumed to be $3500 instead of $4500 (with the 90 percent efficient model still costing $5000), the net benefits would be virtually identical to those of the example in Table H-3. If the 85 percent efficient model cost only $2400 (with the 90 percent efficient model still costing $5000), the measure would actually fall below a 1.00 benefit-cost ratio.

Table H-4. Amortization to Address Multiple Baselines for Early Replacement

Costs		Savings	
Efficiency Measure Cost	$5000	Installed Measure Efficiency	90%
Standard New Product Cost	$4500	Standard New Product Efficiency	85%
Resource Life	15	Existing Efficiency	70%
Existing Product Remaining Life	5	Savings Annual Value (Years 1-5)	$600
Real Discount Rate	3%	Savings Annual Value (Years 6 and Beyond)	$124

Mismatched Timing of Costs Incurred under Baseline and Early Replacement Program Scenarios

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Baseline	$0	$0	$0	$0	$0	$4500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5000
Early Replace	$5000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5000	$0	$0	$0	$5000

Net Costs and Benefits of Early Replacement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	NPV
Costs																					
Baseline	-	-	-	-	-	$366	$366	$366	$366	$366	$366	$366	$366	$366	$366	$366	$366	$366	$366	$366	$3882
Early Replace	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$6231
Net Cost	$407	$407	$407	$407	$407	$41	$41	$41	$41	$41	$41	$41	$41	$41	$41	$41	$41	$41	$41	$41	$2349
Benefits	$600	$600	$600	$600	$600	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$4140
Net Benefits	$193	$193	$193	$193	$193	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$83	$1791
Benefit-Cost Ratio																					1.76

H.3 Free-Riders and Spillover

This section describes how to address free-riders and spillover effects in cost-effectiveness analyses, for those jurisdictions that focus on net savings in BCAs.

In jurisdictions that focus on net savings for their cost-effectiveness analyses:

- The treatment of free-ridership and spillover effects should be a function of the categories of impacts that a jurisdiction chooses to include in the cost-effectiveness test it adopts pursuant to the NSPM BCA Framework outlined in Chapters 2–3.
- With regard to free-riders:
    - Financial incentives paid to free-riders are a cost only if the cost-effectiveness test excludes participant impacts; otherwise the value of the financial incentive to the participant offsets the cost of the financial incentive to the utility system. In other words, the net cost of free-riders is zero under any test that includes participant impacts.
    - No benefits from free-riders should be included in any cost-effectiveness test.
- With regards to spillover:
    - There are no costs associated with spillover in jurisdictions whose cost-effectiveness test includes only utility system impacts. Spillover should increase costs under tests that include participant impacts.

- ○ Spillover increases benefits in every test.

Table H-5 summarizes which categories of impacts are affected by free-rider and spillover effects, as further discussed below.

Table H-5. Categories of Impacts Affected by Free-Riders and Spillover

Category	Free-Riders		Spillover	
	Costs	Benefits	Costs	Benefits
Utility System Impacts	Increase	n/a	n/a	Increase
Participant Impacts	Decrease	n/a	Increase	Increase (if applicable)
Other Impacts	n/a	n/a	Increase (if applicable)	Increase (if applicable)
Total/Net Impact	Increase only if test *excludes* participant impacts; otherwise no net effect	No effect under any test	No increase if test includes only utility system impacts; otherwise an increase	Increase under every test

H.3.1. Applicability and Definitions

This section addresses the economic concepts underpinning how free-ridership and spillover effects should be treated in cost-effectiveness analyses in jurisdictions that choose to focus on net savings. This section does not address the relative merits of focusing on net savings versus focusing on gross savings, as that is beyond the scope of a guidance document focused solely on the construct and application of cost-effectiveness analysis. This section has no relevance to or application for cost-effectiveness analyses in jurisdictions that choose to focus on gross impacts.

Key definitions to consider in applying guidance from this section are as follows:

- *Free-ridership* refers to efficiency program savings that would have occurred in the absence of the program.[87]
- *Spillover* refers to the installation of efficiency measures or adoption of efficiency practices by customers who did not directly participate in an efficiency program but were nonetheless influenced by the program to make the efficiency improvement.[88]

[87] There are three forms of free-ridership: (1) total free-riders—or efficiency program participants who would have installed the same efficiency measures at the same time even if the program had not been run; (2) partial free-riders—or participants who would have made some, but not all, of the efficiency investments they made in the absence of the program; and (3) deferred free-riders—participants who would have made the same efficiency investments in the absence of the program, but at a later date (NREL 2017b).

[88] Spillover can take multiple forms, including both (1) participant spillover—or savings that were influenced by a customer's participation in efficiency program but were beyond those tracked by the program; and (2) non-participant spillover—or savings that were produced by customers who were influenced by a program even though they did not directly participate in it. Participant spillover can be further subdivided into savings that occur at the same site as savings from program participation (known as "inside spillover") and savings that occur at other sites (typically) owned or operated by the same

- *Gross program impacts* are impacts before or without any adjustments for free-ridership and spillover.
- *Net program impacts* include adjustments for free-ridership and spillover.

H.3.2. Economic Treatment of Free-Rider Impacts

This section describes which free-rider impacts should be included in cost-effectiveness analysis in jurisdictions that focus on net savings, given the categories of impacts that such jurisdictions include in their cost-effectiveness tests.

Utility System Impacts

Benefits: No utility system benefits associated with any savings achieved by free-riders should be included in cost-effectiveness analyses of an efficiency program because the program did not cause those benefits.

Costs: Any financial incentives paid to free-riders should be treated as a utility system cost, because they are part of the overall cost to the utility of operating an efficiency program. For example, if a customer that receives a $100 rebate from a utility efficiency program for an efficiency measure that they would have installed absent the program, the utility system has incurred a $100 cost.

Participant Impacts

Benefits: No participant benefits associated with any savings achieved by free-riders should be included in cost-effectiveness analyses of efficiency programs because the participants would have achieved the same benefits absent the program.

Costs: Financial incentives paid to free-rider participants should be treated as a negative cost to participants because such participants would not have received any such financial support absent the program. This reduction in cost to participants cancels out the cost of free-riders to the utility system. Thus, under cost-effectiveness tests that include both utility system and participant impacts, the net cost of free-riders is zero.

Consider the example above in which a customer that receives a $100 rebate from a utility efficiency program for an efficiency measure that they would have installed absent the program. As discussed above, the $100 is a utility system cost. Thus, if the jurisdiction's cost-effectiveness test included utility system impacts (as all tests must) but did not include participant impacts, there would be a net cost from the free-rider of $100. However, that changes if the jurisdiction's cost-effectiveness test also includes participant impacts because $100 cost to the utility system is offset by a $100 benefit to the free-rider participant. Put another way, under a test that includes both utility system and participant impacts, the $100 rebate is what is often called a transfer payment. It has distributional impacts—by moving money between customers—but no *net* cost to customers as a whole (which is the perspective that matters under cost-effectiveness tests that include participant impacts as well as utility system impacts).

customer (known as "outside spillover"). Participant spillover can also be subdivided into savings that are from measures or actions that are same as those that were recorded by the program (known as "like spillover") or from different kinds of efficiency measures (known as "unlike spillover") (NREL 2017b).

Other Types of Impacts

Benefits: No other types of benefits associated with any savings achieved by free-riders (other fuel savings, water savings, environmental emission reductions, public health cost savings, poverty reduction, job creation, energy security, etc.) should be included in cost-effectiveness analyses of efficiency programs because they would have been realized absent the program as well.

Costs: Any other types of costs associated with efficiency investments by free-riders should not be included in cost-effectiveness analyses of efficiency programs because they would also have been incurred absent the program.

Summary of Economic Treatment of Free-Riders

Table H-6 summarizes the proper economic treatment of free-rider benefits and costs for jurisdictions that focus on net (rather than gross) impacts.

Table H-6. Summary of Economic Treatment of Free-Riders

Category	Free-Riders	
	Costs	Benefits
Utility System Impacts	Increase	n/a
Participant Impacts	Decrease	n/a
Other Impacts	n/a	n/a
Total/Net Impact	Increase only if test *excludes* participant impacts; otherwise no net effect	No effect under any test

H.3.3. Economic Treatment of Spillover Effects

This section describes what spillover impacts should be included in cost-effectiveness analysis in jurisdictions that focus on net savings, given the categories of impacts that such jurisdictions include in their cost-effectiveness tests.

Utility System Impacts

Benefits: All utility system benefits associated with spillover effects should be included in cost-effective analyses of an efficiency program because they were caused by the program.

Costs: There are no utility system costs directly associated with spillover effects because, by definition, investments made to produce spillover effects are not subsidized by efficiency programs (i.e., if a customer receives a rebate for installing a measure it is a program participant; spillover effects are produced when customers install measures without taking rebates or other program services).

Participant Impacts

Benefits: In jurisdictions that include participant impacts in their cost-effectiveness test, all spillover participant benefits associated with spillover effects should be included in cost-effectiveness analyses because such effects were caused by the efficiency programs being analyzed.

Costs: All spillover participant costs associated with spillover effects should be included in cost-effectiveness analyses because such effects were caused by the efficiency programs in question.

Other Types of Impacts

Benefits: In jurisdictions that include other types of impacts in their cost-effectiveness test (other fuel impacts, water impacts, environmental impacts, public health impacts, low-income impacts, job impacts, energy impacts, etc.), all other benefits associated with spillover effects should be included in cost-effectiveness analyses because such effects were caused by the efficiency programs under analysis.

Costs: All other types of costs associated with spillover effects should be included in cost-effectiveness analyses because such effects were caused by the efficiency programs under analysis.

Summary of Economic Treatment of Spillover Effects

Table H-7 summarizes economic treatment of spillover benefits and costs.

Table H-7. Summary of Economic Treatment of Spillover Effects

Category	Spillover	
	Costs	Benefits
Utility System Impacts	n/a	Increase
Participant Impacts	Increase	Increase (if applicable)
Other Impacts	Increase (if applicable)	Increase (if applicable)
Total/Net Impact	No increase if test includes only utility system impacts; otherwise, an increase	Increase under every test

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