PART TWO
CHAPTER 3

Assessing the Electricity System Benefits of Energy Efficiency and Renewable Energy

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ABOUT THIS CHAPTER

This chapter provides analysts and policy makers with information about a range of methods they can use to assess the electricity system-related benefits of energy efficiency and renewable energy. It first describes the methods and key considerations for selecting or using the methods. The chapter then provides case studies illustrating how the methods have been applied and lists a range of relevant tools and resources analysts can use to quantify electricity system impacts. Building off the direct electricity impacts discussed in Chapter 2, "Estimating the Direct Electricity Impacts of Energy Efficiency and Renewable Energy," the benefits quantified using methods discussed in this chapter can serve as inputs into subsequent economic assessments discussed in Chapter 5, "Estimating the Economic Benefits of Energy Efficiency and Renewable Energy." Several of the methods and tools described in this chapter can also be used to quantify the emissions impacts of energy efficiency and renewable energy, as discussed in Chapter 4, "Quantifying the Emissions and Health Benefits of Energy Efficiency and Renewable Energy."

3.1. OVERVIEW

Many energy efficiency and renewable energy programs and policies result in reduced demand for electricity from conventional generating resources on the grid. This delivers multiple benefits to the electricity system by:

- Lowering electricity costs for customers and utilities alike, particularly during periods of peak electricity demand[1]
- Improving the reliability of the electricity system and lowering the risk of blackouts, particularly when load is reduced in grid-congested areas
- Reducing the need for new construction of generation, transmission, and distribution capacity[2]

State legislatures, energy and environmental agencies, regulators, utilities, and other stakeholders (e.g., ratepayer advocates, environmental groups) can quantify and compare the electricity system benefits of energy efficiency and renewable energy resources to traditional grid electricity. This information can then be used in many planning and decision-making contexts, including:

- Developing state energy plans and establishing energy efficiency and renewable energy goals
- Conducting resource planning by state utility regulatory commissions or utilities
- Developing demand-side management (DSM) programs
- Conducting electricity system planning, including new resource additions (e.g., power plants), transmission and distribution (T&D) capacity, and interconnection policies
- Planning and regulating air quality, water quality, and land use
- Obtaining support for specific initiatives
- Designing policies and programs

STATES ARE QUANTIFYING THE ELECTRICITY SYSTEM BENEFITS OF ENERGY EFFICIENCY AND RENEWABLE ENERGY POLICIES

Several state policy makers have quantified the electricity system benefits from their energy efficiency and renewable energy measures and determined that the measures are providing multiple benefits, including avoiding the costs of electricity generation, reducing peak demand, and improving electricity system reliability.

The California Public Utility Commission (CPUC) published an evaluation report on the state's energy efficiency programs throughout 2010–2012. These programs resulted in:

- 7,745 Gigawatt-hours (GWh) of savings, enough to power 800,000 homes per year (direct electricity savings)
- Summer peak demand savings of 1,300 Megawatts (MW) (electricity system benefits)
- $5.5 billion in savings for California ratepayers, including the electricity system benefits described above (electricity system benefits and direct electricity savings)

California's energy efficiency programs were also cost-effective; for every dollar invested in energy efficiency programs, savings of $1.31 were achieved.

This chapter is designed to help analysts and decision makers in states and localities understand the methods, tools, opportunities, and considerations for quantifying the electricity system benefits of energy efficiency and renewable energy policies, programs, and measures. While most of the benefits and analytical approaches described in this *Guide* can apply broadly to all types of energy generation and use, the focus of this chapter is primarily on the electricity sector.

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[1] *Just as energy efficiency program economics can be evaluated from a variety of perspectives (total resource costs, program administration costs, and those of ratepayers, participants, and society) so too can the benefits of energy efficiency and renewable energy programs. For each perspective, the benefits of energy efficiency and renewable energy are defined differently. This* Guide *examines the equivalent of the total resource cost perspective, considering benefits (and costs) to the participants and the utility. While other perspectives (including utility costs) are valuable, this* Guide *focuses on those perspectives most significant to policy makers and energy efficiency and renewable energy program administrators. For more information about the different perspectives used to evaluate the economics of programs, see* Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy Makers: A Resource of the National Action Plan for Energy Efficiency, *November 2008, at https://www.epa.gov/sites/production/files/2015-08/documents/cost-effectiveness.pdf.*

[2] *For an overview of the U.S. electricity system, see: https://www.epa.gov/energy/about-us-electricity-system-and-its-impact-environment.*

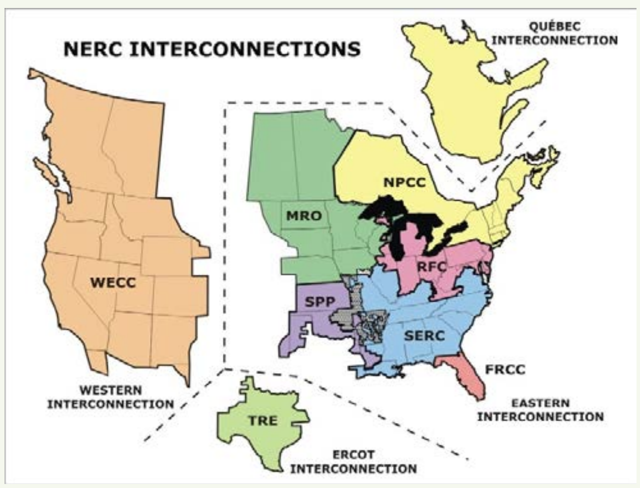
The range of methods and tools described is not exhaustive and inclusion of a specific tool does not imply EPA endorsement.

3.2. APPROACH

The U.S. electricity system is a complex, interconnected system made up of several components—including electricity generation, transmission, and distribution—and the markets by which electricity is bought and sold as described in the box "The U.S. Electricity System." Energy efficiency and renewable energy policies and programs can lead to quantifiable benefits across these multiple facets of the system. When planning an electricity system analysis, it's useful first to review the types of electricity system benefits described in this chapter, select the types of benefits of interest, and explore the ranges of methods available, considering the level of rigor desired and resources available for quantifying the relevant benefits.

THE U.S. ELECTRICITY SYSTEM

It is helpful to understand the nature and complexity of the electricity system before planning an analysis of how it may be affected by energy efficiency or renewable energy policies, programs, and technologies. The power grid is a complex, interconnected system in which most of the electricity is generated at centralized power plants, transmitted over long distances through high-voltage transmissions lines (sometimes across multiple states), and then delivered through local distribution wires to residential, commercial, and industrial end users. The system must generate enough electricity supply to meet demand from all end users and deliver supply through a network of T&D lines. This balancing act takes place in real time, as the grid is limited in its ability to store excess power for later use. Maintaining this balance is challenging because the need for electric services is dynamic, with demand fluctuating depending on the season, the time, and the weather. Supply may also fluctuate based on operating conditions for renewable resources such as solar and wind.



The North American electricity system acts essentially as four separate systems of supply and demand because it is divided into four interconnected grids in the continental United States and Canada: the Eastern, Western, Quebec, and Electric Reliability Council of Texas (ERCOT) Interconnections as depicted in the North American Electric Reliability Corporation (NERC) graphic above. Each interconnection contains power control areas that electricity can be imported or exported easily among numerous power control areas within each system. However, for reliability purposes, they have limited connections between them and are linked by direct current (DC) lines.

System operators across a region decide when, how, and in what order to dispatch electricity from each plant in response to the demand at that moment and based on the cost or bid process. In regulated electricity markets, dispatch is based on "merit order" or the variable costs of running the plants. In markets where regulatory restructuring is active or in wholesale capacity markets, dispatch is based on the generator's bid price into the market. Electricity from the power plants that are least expensive to operate (i.e., the baseload plants) is dispatched first. The power plants that are most expensive to operate (i.e., the peaking units) are dispatched last. The merit order or bid stack is based on fuel costs and plant efficiency, as well as other factors such as emissions allowances prices.

For more information about the electricity system, please see:

- EPA's Website, About the U.S. Electricity System and its Impact on the Environment: https://www.epa.gov/energy/about-us-electricity-system-and-its-impact-environment
- *2017 Electricity System Overview* (U.S. DOE, 2017): https://www.energy.gov/sites/prod/files/2017/02/f34/Appendix--Electricity%20System%20Overview.pdf

Graphic Source: NERC, 2018.

3.2.1. Understanding Primary vs. Secondary Electricity Benefits

For the purposes of this *Guide*, the electricity system benefits of energy efficiency and renewable energy are categorized as either primary or secondary, based on the current frequency of quantification and the prevalence of widely accepted quantification methods. Both categories include generation-related benefits and T&D-related benefits.

Primary Electricity System Benefits

Primary electricity system benefits are quantified often in analyses using methods and tools that are well understood and systematically applied as described in Section 3.2.4., Methods for Quantifying Primary Electricity System Benefits, of this chapter.

Generation-related benefits include:

- Short-run avoided costs of electricity generation or wholesale electricity purchases
- Long-run avoided costs of power plant capacity

T&D-related benefits include:

- Avoided electricity losses during T&D
- Avoided T&D capacity costs associated with building or upgrading T&D systems

Secondary Electricity System Benefits

Secondary electricity system benefits are less frequently assessed and can be more difficult to quantify than primary benefits. The methods for assessing them are less mature than methods for assessing primary benefits and can be diverse, qualitative, and subject to rigorous debate, as described in Section 3.2.5., Methods for Quantifying Secondary Electricity System Benefits, of this chapter.

Generation-related benefits include:

- Avoided ancillary service costs
- Reductions in wholesale market prices
- Avoided risks associated with long lead-time investments, such as the risk of overbuilding the electricity system
- Reduced risks from deferring investments in conventional centralized resources
- Improved fuel diversity and energy security

T&D-related benefits include:

- Increased reliability and improved power quality

USING NET PRESENT VALUE (NPV) WITH BOTH COSTS AND BENEFITS TO COMPARE ENERGY RESOURCES

Decision makers can compare the costs of different energy efficiency and renewable energy resources against each other and against more conventional generating resources by examining their NPV (i.e., the sum of discounted cash flows in terms of costs and savings over the life of the resource). For example, replacing a chiller in a food-processing factory with a more efficient unit incurs a higher capital cost upfront, but reduces annual electricity costs for the customer. Likewise, installing high-efficiency transformers in a new substation can be more expensive than standard equipment in terms of upfront costs, but will waste less electricity over time, thereby reducing variable operating and maintenance costs. The basic concept is to compare the net impact on the cost of power over the lifetime of each alternative that is technically capable of meeting the need. The alternative with the smallest net impact is typically the preferred choice, all other things being equal.

NPV analysis can incorporate multiple electricity system benefits described in this *Guide*, and enable comparison of various options on an equal basis.

Table 3-1 summarizes the traditional costs of generating, transmitting, and distributing electricity, and describes the primary and secondary energy efficiency and renewable energy benefits associated with each type of cost.

Table 3-1: Electricity System Costs and the Primary and Secondary Benefits of Energy Efficiency and Renewable Energy

Aspect of Electricity System	Timing of Costs/Benefits	Traditional Costs	Primary Benefits of Energy Efficiency and Renewable Energy	Secondary Benefits of Energy Efficiency and Renewable Energy
Generation	**Short run**[a]	▪ Fuel ▪ Variable O&M ▪ Emissions allowances	▪ Short-run avoided costs of electricity generation or wholesale electricity purchases	▪ Improved fuel diversity ▪ Improved energy security ▪ Avoided ancillary services costs ▪ Reductions in wholesale market clearing prices ▪ Increased reliability and power quality
	Long run	▪ Capital and operating costs of upgrades ▪ Fixed O&M[b] ▪ New construction to increase capacity	▪ Long-run avoided costs of power plant capacity	▪ Reduced risks from deferring investment in conventional, centralized resources pending uncertainty in future regulations ▪ Avoided risks associated with long lead-time investments (e.g., risk of overbuilding the electricity system)
T&D	**Short run**[a]	▪ Costs of energy losses	▪ Avoided electricity losses during T&D	▪ None
	Long run	▪ Capital and operating costs of upgrades ▪ Fixed O&M ▪ New construction to increase capacity	▪ Avoided T&D capacity costs	▪ Increased reliability and power quality

[a] *Note that short-run costs and benefits, which include the marginal costs of operating the system, also accrue in the long run.*

[b] *Fixed operation and maintenance (O&M) costs could also be impacted in the short run by large changes to the operation of generating units.*

3.2.2. Selecting What Benefits to Evaluate

Some state policy makers may not be interested in estimating all types of electricity system benefits, or they may be considering programs that deliver benefits in only some areas. It is generally common practice for most, if not all, policy makers to evaluate all of the primary benefits for energy efficiency and renewable energy projects or programs.

Secondary benefits, however, may be both harder to quantify and, in some cases, smaller than primary benefits. For these reasons, policy makers with limited time and resources may choose to devote the majority of their time to evaluating primary benefits.

For secondary benefits, the need for detailed estimation can vary depending on several factors, including:

- The type of energy efficiency or renewable energy resource being considered
- Regulatory or system operator study requirements
- Available resources (e.g., computers, staff, and data)
- Whether certain needs or deficiencies have been identified for the existing electricity system

Analysts often devote their limited staff and computing power to quantifying benefits that are likely to yield the most reliable and meaningful results, and address other benefits qualitatively.

3.2.3. Selecting a Method for Quantifying the Electricity System Benefits

When choosing a method for estimating electricity system benefits, analysts:

- Explore the types of methods or tools available for quantifying the specific benefit(s)
- Evaluate the rigor of analysis needed (e.g., screening level vs. regulatory impact analysis) plus any data needs, financial costs, or technical expertise required

Methods for Quantifying Electricity System Benefits

Analysts can use a range of mature methods—from basic to sophisticated—to quantify the electricity system benefits of energy efficiency and renewable energy policies and programs, as introduced below. As described earlier, however, the availability of mature, systematically applied methods for quantifying the electricity system benefits of energy efficiency and renewable energy depends on whether the analyst is quantifying primary or secondary electricity system benefits. When quantifying primary benefits, for example, analysts can choose from a range of well-established basic-to-intermediate and sophisticated approaches. When quantifying secondary benefits, however, analysts can find basic-to-intermediate quantification methods to assess most benefits but fewer applicable sophisticated methods.

Basic-to-Intermediate Methods for Quantifying Electricity System Benefits

Basic-to-intermediate methods typically include:

- Spreadsheet-based analyses
- Adaptation of existing studies or information

These methods generally rely on relatively simple relationships and analytic structures. Many are conceptually similar to sophisticated methods, but use additional simplifying assumptions (e.g., proxy plants, system averages).

For example, when estimating impacts of an energy efficiency or renewable energy resource, analysts may use simplifying assumptions (e.g., for generating units displaced or for emissions rates at the time of displacement) instead of a sophisticated economic dispatch model. While an economic dispatch model would identify specifically those units on the margin (i.e., the last units expected to be dispatched, which are most likely to be displaced by energy efficiency or renewable energy) in each time period, a basic method may pair impacts to the general type(s) of unit(s) expected to be on the margin given the existing units and/or past behavior.

When to use: Analysts can use estimation methods for preliminary assessments or screening exercises, such as comparing the cost of an energy efficiency or renewable energy option with a previous projection of avoided costs or the cost of a proxy plant. Although they are less robust than sophisticated modeling methods, basic methods require less data, time, and resources and can therefore be useful when time, budget, or data are limited.

Sophisticated Methods for Quantifying Electricity System Benefits

Sophisticated methods typically use dynamic, state-of-the-art electricity system models that:

- Simulate and project the response of electric generating units to actions that influence the level of energy efficiency and renewable energy resources.
- Calculate the resulting effects on metrics such as wholesale and retail prices, generation mix, fuel consumption, T&D system adequacy, emissions, and others.

These models have more complex structures and interactions than the basic methods, and are designed to capture the fundamental behavior of the power sector using techno-economic, sometimes referred to as engineering-economic, relationships or econometric methods. Sophisticated methods require additional input assumptions compared with basic methods, but they can generate more complex insights about the impacts on the electricity system.

For example, capacity expansion models can depict how the operations and/or capacity needs of the existing electric grid are likely to change with the adoption of an energy efficiency or renewable energy resource. Some models can also predict energy prices, emissions, and other market conditions.

These models are complex to set up and can be costly. Developing a detailed representation of the electricity system can involve many individual input assumptions, and it is helpful to validate, benchmark, or calibrate complex models against historical data and established forecasts such as those produced under the Energy Information Administration (EIA) Annual Energy Outlook (AEO). Access to confidential system data can also pose a challenge to conducting rigorous analysis of avoided costs. However, in many cases, datasets already exist for regional and utility planning analyses, and EIA datasets are free and publicly available. Furthermore, existing power sector models have the benefit of being well understood and mature.

When to use: Analysts can use sophisticated models when a high degree of precision and analytic rigor is required; when sufficient time, budget, and resources are available; and when sufficient data are available.

Table 3-2 describes the strengths and limitations of each method for quantifying electricity system benefits and examples of when each method is appropriate to use.

Table 3-2: Strengths and Limitations of Basic vs. Sophisticated Methods of Estimating Electricity System Benefits

Strengths	Limitations	When to Use
Basic-to-Intermediate Methods		
▪ Transparent assumptions ▪ Easy-to-understand method ▪ Modest level of time, technical expertise, and labor required ▪ Inexpensive ▪ Readily available for quantifying nearly all primary and most secondary electricity system benefits	▪ May be imprecise and less credible than other methods ▪ May be inflexible ▪ May not be able to reflect unique load characteristics of different energy efficiency and renewable energy programs ▪ Not applicable for long-term projections ▪ Does not typically account for imported power ▪ Does not account for myriad of factors influencing dispatch on a local scale, such as transmission constraints or reliability requirements	▪ For preliminary studies ▪ When time and/or budget are limited ▪ When limited data resources are available
Sophisticated Methods		
▪ May include representation of electricity system dispatch and, in some cases, optimally locate and determine capacity expansion ▪ More rigorous than other methods ▪ May be perceived as more credible than other methods, especially for long-term projections ▪ Allows for sensitivity analysis ▪ Readily available for quantifying most primary electricity system benefits	▪ May be less transparent than spreadsheet methods ▪ Labor- and time-intensive ▪ Often involves high software licensing costs ▪ Requires assumptions that have large impact on outputs ▪ May require significant technical experience ▪ Limited availability for quantifying secondary benefits	▪ When a high degree of precision and analytic rigor is required ▪ When sufficient time and budget resources are available ▪ When sufficient data resources are available

Choosing Between Methods for Quantifying Primary Electricity System Benefits

Choosing between methods involves considering:

- Range of methods available for the benefit(s) of interest
- Level of resources available
- Level of rigor required

Some benefits, particularly primary electricity system benefits, have numerous basic-to-sophisticated methods available for quantifying them while others, such as secondary electricity system benefits, may be more limited in what methods are available for analyses. For benefits where multiple types of quantification methods exist, it is helpful to note that basic and sophisticated methods are not mutually exclusive but may be used in a complementary way.

An influencing factor can be the breadth of the benefits quantified by a particular method. Many of the sophisticated models discussed in this chapter quantify several different benefit impacts (e.g., energy, emissions, economic, and others), and are accordingly mentioned multiple times throughout this *Guide.* Analysts interested in assessing benefits beyond electricity system impacts may consider methods that quantify additional benefits.

Assuming the availability of both basic and sophisticated methods, analysts often choose an approach based on the resources available and the level of rigor desired. The rigor with which decision makers can or may want to analyze the electricity system benefits of energy efficiency and renewable energy depends on:

- Type of benefit being analyzed
- Energy efficiency or renewable energy proposal's status in the development and design process
- Level of investment under consideration
- Regulatory and system operator requirements
- Resources (e.g., software, staff, time) available for the analysis
- Utility or region (for some benefits)

Section 3.2.4., "Methods for Quantifying Primary Electricity System Benefits" and Section 3.2.5., "Methods for Quantifying Secondary Electricity System Benefits," describe in greater detail the methods generally used in practice when quantifying primary and secondary electricity system benefits, respectively.

3.2.4. Methods for Quantifying Primary Electricity System Benefits

Many energy efficiency and renewable energy policies and programs reduce demand for electricity from conventional generating resources on the grid. This reduced demand can lead to benefits on the generation side of the electricity system, such as the avoided fuel or variable O&M costs in the short run and the avoided capital and operating costs associated with investments in new power plant capacity in the long run. This reduced demand can also lead to benefits on the T&D side of the electricity system. This includes the avoided losses (and costs) of electricity during T&D in the short run and the avoided capital and operating costs associated with investments in new T&D capacity in the long run.

The section "Generation Benefits: Avoided Costs," below, describes the methods for quantifying generation-related electricity system benefits and the section "Transmission and Distribution Benefits" describes methods for quantifying the T&D-related electricity system benefits. Analysts can use these methods to compare the impacts of their energy resources.

Generation Benefits: Avoided Costs

New energy efficiency and renewable energy resources may result in avoided electricity and capacity costs from generating units in both the short run (i.e., typically 5 years or fewer) and in the long run (i.e., typically 5 to 25 years).

- *Short-run avoided costs* consist of avoided fuel, variable O&M, and emissions allowances that can be saved at those generating units that would operate less frequently as a result of new energy efficiency and renewable energy resource additions.
- *Long-run avoided costs* consist largely of the capital and operating costs associated with new generation capacity and T&D capacity that are avoided or deferred by energy efficiency and renewable energy resources.[3,4]

Short-run and long-run avoided cost estimates generally depend on the comparison of two cases:

1. A baseline or reference case without the new resource
2. A case with the new resource, which when considering a demand-side resource includes a reduction in the load or load decrement

Both cases involve projections of future conditions and are subject to many uncertainties that influence electricity markets (e.g., fuel prices, construction costs, environmental regulations, and market responsiveness to prices). Avoided costs are calculated as the difference between these two cases and, consequently, they can be very sensitive to the underlying assumptions for either or both cases. The level of uncertainty is greatest in long-run avoided cost calculations that require projections far out into an uncertain future.

To address this uncertainty, analysts may want to consider performing sensitivity or scenario analyses on both the underlying business-as-usual (BAU) scenario (e.g., on demand growth, fuel prices) and on the key drivers of the case with the new resources (e.g., on the cost or timing of new resources) to gauge the potential range of results.

Short-Run Avoided Costs of Electricity Generation or Wholesale Electricity Purchases

The two types of methods for quantifying short-run avoided costs of electricity generation or wholesale electricity purchases are basic-to-intermediate and sophisticated. Basic-to-intermediate methods typically involve an active role for analysts in making assumptions, including deriving avoided cost characteristics of displaced generating units from a historical proxy unit or historical dispatch behavior for a group of units within a region. Sophisticated methods are usually more dynamic, using energy-related models that represent the interplay of future assumptions within the electricity or energy system. To calculate short-run avoided costs, sophisticated methods predict electricity generation responses in relation to multiple factors, including, but not limited to emissions controls, fuel prices, dispatch changes, and new generation resources.

SHORT-RUN AVOIDED COSTS

Short-run avoided costs of electricity generation are the operating costs of marginal units. Operating costs include fuel, variable O&M, and marginal emissions costs. In a competitive market, wholesale electricity prices will reflect the system's actual costs for operating marginal units in the bids that generators submit.

Quantifying the short-run avoided costs of energy efficiency and renewable energy initiatives, whether using basic-to-intermediate or sophisticated methods, involves the steps presented in Figure 3-1:

1. Estimate the energy efficiency or renewable energy operating characteristics.
2. Identify the marginal units to be displaced.

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[3] *As noted earlier, in the long run, it is mostly energy efficiency and distributed renewable energy generation capacity that is deferring T&D costs as grid-scale renewable energy resources are adding capacity and their need for T&D infrastructure is similar to traditional generating units.*

[4] *Sometimes the short-term and long-term effects of energy efficiency and renewable energy measures are referred to as "operating margin" and "build margin," respectively (Biewald, 2005).*

3. Identify the operating costs of marginal units to be displaced.
4. Calculate the short-run avoided costs of electricity generation.

Basic-to-intermediate methods require analysts to make assumptions for each of the above steps, while sophisticated methods automate each step using an economic dispatch model once the analyst defines the energy efficiency or renewable energy resource. Each of these steps are described in greater detail below for both basic-to-intermediate and sophisticated methods.

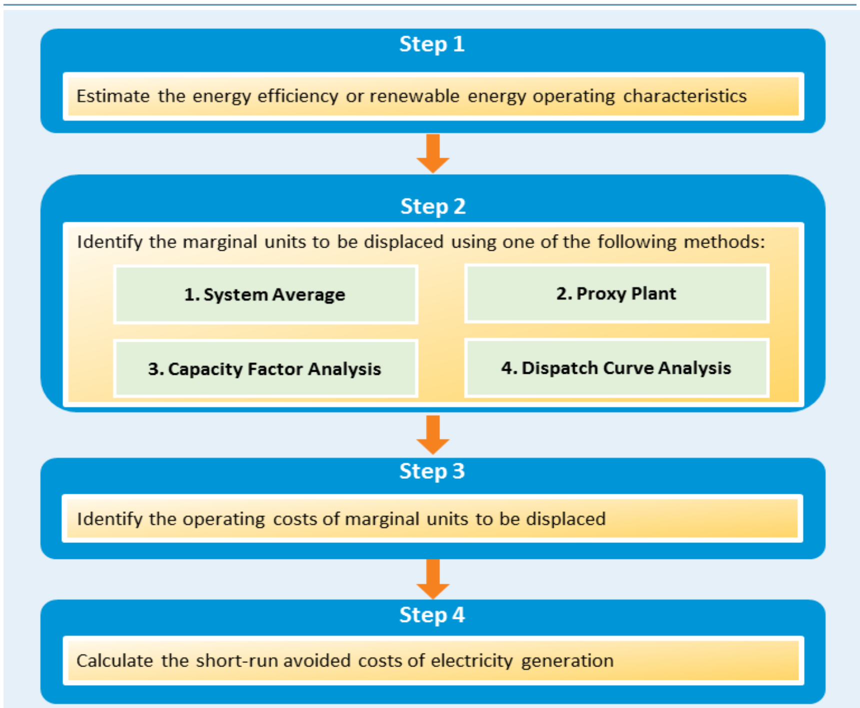
Basic-to-Intermediate Methods for Estimating Short-Run Avoided Costs

When estimating short-run avoided costs using basic-to-intermediate methods, analysts will make a variety of assumptions and/or choices within each step, as described below.

Step 1: Estimate the Energy Efficiency or Renewable Energy Operating Characteristics

The first part of estimating avoided costs of energy efficiency and renewable energy is to estimate the amount of electricity (in kilowatt-hours [kWh]) the energy efficiency measure is expected to save or that the renewable energy initiative is expected to generate over the course of a year and its lifetime. Methods for estimating this saved or generated electricity are described in Section 2.2., "Approach" of Chapter 2, "Estimating the Direct Electricity Impacts of Energy Efficiency and Renewable Energy."

Figure 3-1: Steps for Estimating Short-Run Avoided Costs



In addition to estimating annual impacts, it may be desirable to estimate the timing of impacts within a year, either hourly or on some less frequent interval. The impacts of energy efficiency and renewable energy resources that either reduce generation requirements or add additional generating capacity at the time of peak demand, when natural gas combustion turbines[5] may be operating, will differ from those that affect the system during periods of low demand when baseload plants may be the only plants operating.

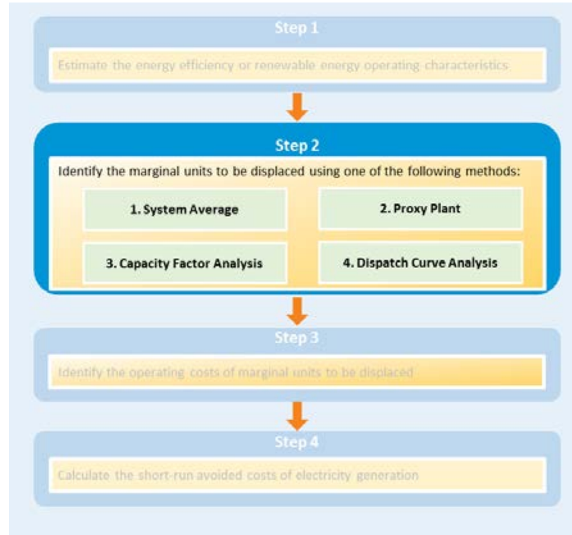
In the case of energy efficiency measures, load impact profiles describe the hourly changes in end-use demand resulting from the program or measure. In the case of renewable energy resources, the generation profiles (for wind or photovoltaics [PV], for example) are required. The time period can range from two- or three-hour intervals, such as peak, off-peak, and shoulder periods, to 8,760 hourly intervals. These data are used to identify more precisely what specific generation or generation types are displaced by the energy efficiency and renewable energy resources.

Several sources are available to help predict the generation or load profiles of different kinds of renewable energy and energy efficiency projects and are listed in Section 3.4., "Tools and Resources." In the absence of specific data on the

[5] *Natural gas combustion turbines are single cycle units which typically operate in times of peak demand, and are less efficient than natural gas combined-cycle units which run more frequently throughout the year (U.S. DOE, 2013a).*

load impact or electricity profile of the energy efficiency or renewable energy resource, analysts will need to use their judgment to assess the timing of that resource's impacts.

Step 2: Identify the Marginal Units to Be Displaced



The next step is to identify the units and their associated costs that are likely to be displaced by the energy efficiency or renewable energy resource(s). While this Step 2 section discusses different methods to estimate the marginal units specific to estimating avoided cost benefits, these same methods support the estimation of emissions benefits of energy efficiency and renewable energy discussed in Section 4.2.2., "Step 2: Quantify Emissions Reductions" of Chapter 4, "Quantifying the Emissions and Health Benefits of Energy Efficiency and Renewable Energy."

In each hour, electric generating units are generally dispatched from least to most expensive, on a marginal cost basis, until demand is satisfied. A host of complexities involved in dispatching the generating system include generator start-up and shut-down operating constraints and costs, and transmission and reliability considerations, among other factors. However, in concept, the unit that is displaced is the last unit to be dispatched, and is referred to as the "marginal" unit. Estimating the benefits of energy efficiency and renewable energy resources requires identifying marginal units and their avoided costs.

Identifying the marginal units can be estimated using basic-to-intermediate methods, such as spreadsheet analysis of market prices, marginal cost data, or inspection of regional dispatch information (i.e., fuel mix and capacity factor by fuel type). Non-modeling estimation methods, such as using a previously estimated avoided cost projection, may be more appropriate when time, budget, and access to data are limited, but they result in an approximation of the costs of avoided electricity generation. Consequently, analysts should consider whether the estimation method is an acceptable representation of the actual system. For example, already-available avoided costs may be out of date or may not match the timing of the impacts of the energy efficiency or renewable energy resource being considered. Reported or modeled avoided costs may not reflect some of the other complexities identified above, therefore looking at variable fuel and O&M may be misleading.

There are several basic-to-intermediate methods analysts can use to identify and evaluate the marginal units:

- *Basic Method 1: System Average* – Use an average of system costs of the generating units in the system to represent the marginal unit.
- *Basic Method 2: Proxy Plant* – Select one unit as a proxy for representing the marginal unit, typically correlated with what is expected to be on the margin during the time of day that the energy efficiency or renewable energy resource impacts would occur.
- *Basic Method 3: Capacity Factor Analysis (also known as Displacement Curve Analysis)* – Build and use a displacement curve using factors that are based on a unit or power plant's capacity factor or other characteristics that correlate with the likelihood of a unit type being displaced.
- *Intermediate Method 1: Dispatch Curve Analysis* – Couple the historical hourly generation of generating units in a region with the hourly load reduction profiles of energy efficiency and renewable energy resources to determine hourly generating cost characteristics of marginal units.

These four basic-to-intermediate methods are described in more detail in this section and are referenced below in Table 3-4. They are distinguished primarily by how they determine the characteristics of the units that are being displaced by the energy efficiency or renewable energy resource. For all methods, once the kWh impacts are mapped to the appropriate marginal generating units, then operating costs of the marginal units can be identified in "Step 3: Identify the Operating Costs of Marginal Units to Be Displaced" and cost savings (and emissions impacts described in Chapter 4) can then be estimated in "Step 4: Calculate the Short-Run Avoided Costs of Electricity Generation."

Basic Method 1: System Average

The simplest method that studies have used to estimate the impacts of the displaced unit, absent any detailed information on the regional electricity system, is to use an average of costs of the generating units in the system to represent the marginal unit.[6]

Most analysts recognize, however, that some types of generating units are almost never on the margin and therefore should not be included in the characterization of the marginal unit. For example, depending on the location, nuclear units and renewable resources may rarely be on the margin and unlikely to be displaced by energy efficiency or new renewable energy resources in the short run. Moreover, the average variable operating costs of the electricity system can differ greatly from the variable operating cost of the marginal source of generation.

To partially address this shortcoming, units that typically serve baseload and other units with low variable operating costs (e.g., hydro and other renewables) can be excluded from the regional or system average. This is an improvement over the system average, but due to the assumed average impacts regardless of the time the impacts are taking place, using "non-baseload" generating costs still do not capture the potential impact of a variety of energy efficiency and renewable energy resources, each with differing impact patterns. This method is an option despite these limitations.

Basic Method 2: Proxy Plant

Based on the expected operating characteristics of the energy efficiency or renewable energy resource determined in "Step 1: Estimate the Energy Efficiency and Renewable Energy Operating Characteristics," above, a single generating unit, or "proxy plant," can be determined to represent the short-run operating characteristics of the displaced generation. For example, for all impacts during the peak period, a natural gas-fired combustion turbine could be used as a proxy to estimate impacts. During baseload periods, a coal plant could be used, while in shoulder periods a natural gas combined-cycle (NGCC) plant might be used. The details would depend on the system being analyzed.

This method should only be used when the operating characteristics of the energy efficiency or renewable energy resource are likely to occur during a particular time period (e.g., peak hours during the summer) because the marginal generating unit will be more likely to be the same type of unit during similar periods. If there is minimal variability in when energy efficiency or renewable energy impacts are likely to occur, a user could create a weighted proxy plant (e.g., 60 percent of one plant's characteristics and 40 percent of another plant's characteristics), although advancing to one of the methods described next would yield a more robust analysis.

Basic Method 3: Capacity Factor Analysis (also called Displacement Curve Analysis)

One time-dependent method for estimating what will be displaced by energy efficiency or renewable energy involves displacement curves. Plants serving baseload can be generalized as operating all of the time throughout the year because their operating costs are low and because they are typically not suitable for responding to the many fluctuations in load that occur throughout the day. As a result, they would not be expected to be displaced

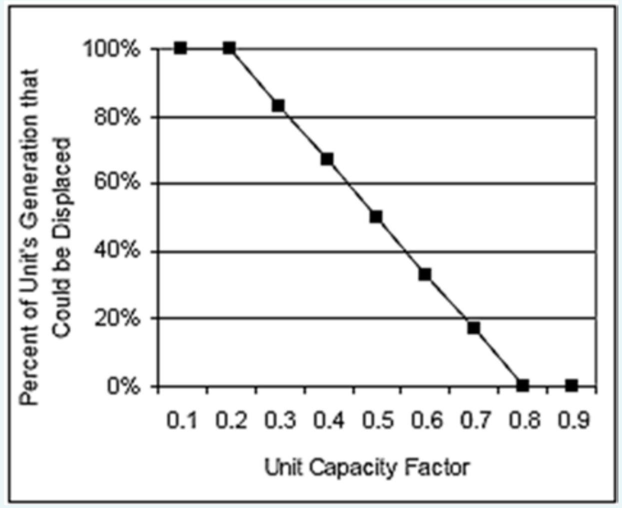
[6] *Analysts looking to quantify avoided costs and emissions reductions should consider one of the other methods.*

with any frequency. These plants would have high capacity factors (e.g., greater than 0.8 or 80 percent), which is the ratio of how much electricity a plant produces to how much it could produce, running at full capacity, over a given time period. Load-following plants, in contrast to baseload plants, can quickly change output, have much lower capacity factors (e.g., less than 0.3 or 30 percent) and are more likely to be displaced.

A location-specific displacement curve can be developed to identify what generation is likely to be displaced. The curve would reflect the likelihood of a unit being displaced, based on its expected place in the dispatch order. While many unit characteristics could be used to construct a displacement curve including unit type (e.g., coal steam, nuclear, combustion turbine), heat rate, or pollution control equipment in place, a unit's capacity factor is a reasonable representation of the likelihood of a generating unit to be displaced by an energy efficiency or renewable energy measure and is illustrated in Figure 3-2.

Figure 3-2: Displacement Curve Based on Capacity Factors

Sample curve for relating displacement to capacity factor.



Source: Keith and Biewald, 2005.

The following steps are used to construct a displacement curve based on capacity factor and to estimate the percentage of total hours each type of unit (e.g., coal-fired steam, oil-fired steam, combined-cycle gas turbine, etc.) is likely to be on the margin:

1. *Identify the generating unit types in your region and their associated capacity factors.* These capacity factor estimates can be based on an analysis of actual dispatch data, modeling results, or judgment.[7]

2. *Construct a displacement curve by determining the relationship between capacity factor and percent of time a unit or unit type will be displaced*. The relationship between capacity factor and percent of time it will be displaced could be determined analytically (e.g., examining historical data on the relationship between a unit's capacity factor and the time it is on the margin), or more likely a judgment could be made about this relationship, as depicted in Figure 3-2. When constructing the displacement curve, operating characteristics determined back in "Step 1: Estimate Energy Efficiency and Renewable Energy Operating Characteristics," should be used to make any adjustments to the unit capacity factor.

3. *Calculate the percentage of total hours each unit or unit type is likely to be on the margin.* Use the following calculations to estimate the percentage:

    a. Multiply each unit or unit type's historical generation for the representative time period determined in Step 1, above, by the percentage that could be displaced based on the displacement curve.

    b. Take the potential generation that could be displaced for each unit and divide it by the total potential generation that could be displaced to estimate the fraction of time (%) the unit or unit type will be on the margin.

[7] *For historical data on capacity factors for individual plants, see EPA's eGRID database at: https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid. For additional data sources, Section 3.4., [Tools and Resources](#).*

Figure 3-2 illustrates this concept using capacity factors to build a displacement curve. Plants that serve baseload on the right side of the curve, such as nuclear units, are assumed to be very unlikely to be displaced by energy efficiency or renewable energy; peak load plants on the left, such as combustion turbines, are much more likely to be displaced.

A displacement curve may not perfectly capture all aspects of electricity system operations, however. Capacity factors are average statistics and therefore may not be truly representative of operations during specific times of day or times of the year. For example, during shoulder months (spring and fall), baseload generators can be shut down for maintenance. When this occurs, their capacity factor will fall, indicating in the displacement curve that they are on the margin, when they are actually not operating. In addition, certain types of units will be on the margin at different times of the day as load increases and falls. If displacement caused by the energy efficiency or renewable energy resource is expected to occur at a specific time of day, using average capacity factors may misrepresent the actual displacement that would occur during that time of day.

Intermediate Method 1: Dispatch Curve Analysis

While capacity factor analyses provide a way to estimate the characteristics of the marginal unit based on the relationship of a unit type's characteristic (e.g., capacity factor) with how often that unit type will be displaced, dispatch curve analyses estimate the characteristics and frequency of each generating unit on the margin by examining historical hourly dispatch data. Dispatch curves, also referred to as load duration curves, represent the regional electricity demand over a period of time in descending order. When combined with the dispatch characteristics of the marginal generating units serving the load for each unit of time, a load duration curve illustrates the generating unit types that are dispatched to meet that demand, effectively creating a dispatch curve.

Generating units are typically dispatched in a predictable order that reflects the demand on the system and the cost and operational characteristics of each unit. These plant data can be assembled into a generation "stack," with lowest marginal cost units on the bottom and highest on the top. A dispatch curve analysis matches each load level with the corresponding marginal supply (or type of marginal supply).

Table 3-3 and Figure 3-3 provide a combined example of a load duration and dispatch curve that represents 168 hours (a 1-week period) during which a hypothetical energy efficiency or renewable energy resource would be operating. This hypothetical power system has 10 generating units, labeled 1 through 10. The third column shows the number of hours that each unit is on the margin.

Table 3-3: Hypothetical Load for 1-Week Period: Hours on Margin

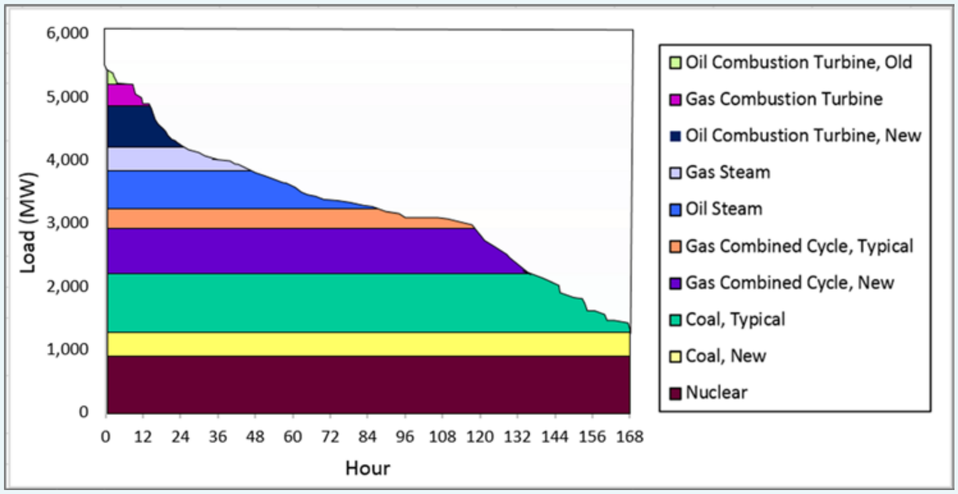
Unit	Unit Name	Hours on Margin
1	Oil Combustion Turbine, Old	5
2	Gas Combustion Turbine	10
3	Oil Combustion Turbine, New	9
4	Gas Steam	21
5	Oil Steam	40
6	Gas Combined-Cycle, Typical	32
7	Gas Combined-Cycle, New	17
8	Coal, Typical	34
9	Coal, New	0
10	Nuclear	0

Date required for constructing a dispatch curve:

- Historical utilization of all generating units in the region of interest
- Operating costs and emissions rates (to support emissions estimation, as described in Chapter 4) of the specific generating units, for the most disaggregate time frame available (e.g., seasonally, monthly)
- Hourly regional loads
- Electricity transfers (If available) between the control areas of the region and outside the region of interest (because the marginal resource may be coming from outside the region)

See Section 3.4., "Tools and Resources," for data sources that can be used for obtaining operating costs, historical utilization data, and regional electricity transfers. When generator cost data are not available, capacity factors[8] for conventional generating units can be used to approximate the relative cost of the unit (those with the highest capacity factors are assumed to have the lowest cost). As an exception, variable power resources such as wind and hydropower are assumed to have lower operating costs than fossil fuel or nuclear units.

Figure 3-3: A Hypothetical Hourly Dispatch Curve Representing 168 Hours by Generation Unit, Ranked by Load Level



The dispatch (i.e., load duration) curve is the curve at the top of the bars in this figure and it represents demand over a period of time. When combined with the dispatch characteristics represented under the curve, the load duration curve line also acts as a dispatch curve.

Source: ICF recreated chart based on Keith and Biewald, 2005.

Operational data (or simplifying assumptions) regarding electricity transfers between the control areas of the region and hourly regional loads can be obtained from the independent system operator (ISO) or other load balancing authority within the state's region.

When to use: Dispatch curve analysis is commonly used in planning and regulatory studies. It has the advantage of incorporating elements of how generation is actually dispatched while retaining the simplicity and transparency associated with non-modeling methods. However, this method can become labor-intensive relative to other non-modeling methods for estimating displaced emissions if data for constructing the dispatch curve are not readily available. Another limitation is that it is based on the assumption that only one unit will be on the margin at any given time; this generally is not true in most regions.

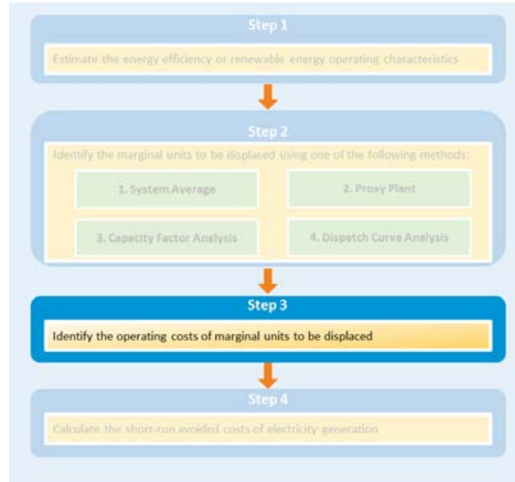
Relationship to basic methods: Methods described earlier, such as Basic Method 3: Capacity Factor Analysis, can support the development of a simplified dispatch curve. For example, capacity factors can be used to "fill" the horizontal segments on the curve as shown in Figure 3-3. One can assume that units with capacity factors greater than 80 percent can fill the baseload segments and that peaking units, with the lowest capacity factors, would fill the peak segments. Units with capacity factors between 80 and 60 percent would fill the next slice of the dispatch curve, and so on. The resolution would reflect available data or the ability to develop meaningful assumptions. The hope is that the level of aggregation is such that the units' characteristics are generally similar and, as such, the marginal unit would be approximated by the group average. If data allows, it is possible to take into account differences in units that drive their costs and emissions (e.g., general unit type and burner type, the presence of pollution control equipment, unit size, fuel type).

Forms of dispatch curves: Dispatch curves may take many forms, highlighting the various types of data listed above. For example, the dispatch curve in Figure 3-3 above plots demand for electricity over a period of time. Another type of dispatch curve used by planners plots system capacity to meet demand against variable operating costs of units. The

[8] *Capacity factors can be obtained from EPA's eGRID database at: https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid.*

curve depicted in the box "Estimating Short-Run Wholesale Market Price Effects: An Illustration," shown and discussed later in the "Reduction in Wholesale Market Clearing Prices" section of this chapter, is an example of this type of curve. Regardless of the form used, dispatch curves offer analysts a predictable way of discerning which units will be dispatched given a level of demand.

Step 3: Identify the Operating Costs of the Marginal Units to Be Displaced

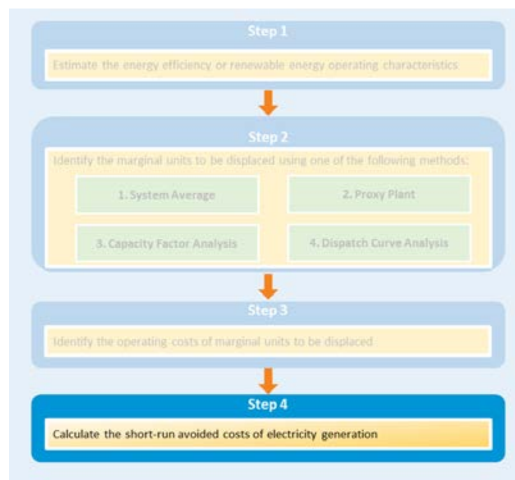


The third step of the analysis involves quantifying the avoided electricity costs (and as described in Chapter 4, Section 4.2.2., "Step 2: Quantify Expected Emissions Reductions") expected from displacing generation. The calculation process varies depending on whether the market is regulated or restructured:

- *In regulated markets,* short-run avoided electricity costs typically include fuel costs, variable O&M costs, and marginal emissions costs for the highest-cost generator in a given hour.[9]
- *In restructured markets,* where regional transmission organizations (RTOs) administer regional wholesale power markets, economic dispatch is conducted on the basis of bid prices rather than generators' marginal costs.[10] This information is available at each ISO's website (see Section 3.4., "Tools and Resources," at the end of this chapter for the websites of individual ISOs).

For longer-term analysis, it is necessary to forecast cost increases. Historical hourly operating costs for the marginal unit (i.e., regulated markets) or market prices (i.e., restructured markets) can be escalated using forward market electricity prices, although the forecast time frame is limited.[11, 12]

Step 4: Calculate the Short-Run Avoided Costs of Electricity Generation



Electricity impacts are mapped to the characteristics of the displaced marginal units to calculate the short-run avoided costs of electricity generation. For each hour or time-of-use period, multiply the cost of the marginal unit or hourly electricity market price by the reduction in load (for demand-side resources) or the increase in generation (for supply-side resources), as estimated using techniques described in Chapter 2. Typically, avoided costs are expressed as the annual sum of these avoided costs for each hour or other time period.

For basic-to-intermediate methods, the estimated electricity impacts (reduction in load or electricity supplied) are mapped to the displaced electricity information. For example, if hourly impacts are estimated, hourly kWh savings are multiplied by hourly avoided costs estimates. The

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[9] *For data sources for control area hourly marginal costs, see the U.S. Federal Regulatory Commission (FERC) form 714 at: https://www.ferc.gov/docs-filing/forms/form-714/view-soft.asp.*
[10] *In theory, bid prices are equivalent to a generator's marginal cost, but considerations such as the costs of starting up and shutting down the unit will also factor in.*
[11] *Forward electricity prices are available from energy traders and industry journals such as Platt's MegaWatt Daily, available at: https://www.platts.com/products/megawatt-daily*
[12] *Long-term electricity and fuel price projections can be found in EIA's Annual Energy Outlook (AEO), available at: https://www.eia.gov/outlooks/aeo/*

summation of these hourly values represents the impact of the energy efficiency or renewable energy resource on costs.[13] Once an analyst calculates the avoided costs (i.e., benefits), analysts can compare them to the costs of implementing energy efficiency and renewable energy measures to understand the net cost or benefit of those measures.

To illustrate how all four steps can be applied to estimate short-run avoided costs, the "Estimating Short-Run Avoided Costs" box depicts an example where the avoided costs are estimated after the capacity factor analysis method was used to identify the marginal units displaced.

Limitations of Basic-to-Intermediate Methods

These basic-to-intermediate methods have some limitations that should be considered when choosing a method:

- Methods that rely on historical data are more accurate when applied for similar conditions to those from when the data were collected. Substantial changes in costs or performance of generation, or other restrictions on their operations (e.g., climate legislation, requirements for a renewable portfolio standard) could fundamentally change the operation of the system and the implied dispatch curve.
  - Even without such fundamental changes, the system modifies over time as new units and energy resource types are added, existing units are retired, and units shift in dispatch order. Analyses based on historical data do not capture these shifts, so to the extent that estimates are being developed for the future, these types of basic-to-intermediate methods must be used with caution.
- These methods may not adequately account for benefits in cases where increases in energy efficiency or renewable energy result in reductions in generation outside the region of interest (e.g., in another state or region).

ESTIMATING SHORT-RUN AVOIDED COSTS

To illustrate the described approach for estimating short-run avoided costs, consider the case of a state that wishes to evaluate the potential benefits of an energy efficiency program. Sample calculations are illustrated in the accompanying table.

Step 1: The state estimates that the energy efficiency program would reduce electricity demand as shown in the Avoided Electricity column (based on an analysis of annual savings from the typical system and a typical load shape).

Step 2: Using a capacity factor analysis, the state estimates that natural gas combustion turbines are typically on the margin during peak periods for both summer and winter, a mix of NGCC units and natural gas-fired steam units (about 50 percent of each) are on the margin during shoulder periods, and existing coal-fired generators (pulverized coal) are typically on the margin during the off-peak periods.

Step 3: The hypothetical avoided costs associated with each of these marginal generating technologies are estimated based on typical variable operating and fuel costs for those types of units estimated to be on the margin. The results are show in the Avoided Electricity Cost for Time Period column.

Step 4: The Total Avoided Electricity Cost column shows the result of multiplying the Avoided Electricity column by the Avoided Electricity Cost for Time Period column. Summing across all periods yields the expected avoided costs for one year.

SAMPLE CALCULATION OF SHORT-RUN AVOIDED ELECTRICITY COSTS

Time Period	Avoided Electricity (MWh)	Avoided Electricity Cost for Time Period ($/kWh)	Total Avoided Electricity Cost ($)
Summer Peak (912 hours)	123,120	0.08	9,234,000
Summer Shoulder (1,368 hours)	153,900	0.06	8,772,300
Summer Off-Peak (1,368 hours)	20,520	0.03	513,000
Winter Peak (1,278 hours)	115,020	0.07	8,051,400
Winter Shoulder (1,917 hours)	143,775	0.06	8,195,175
Winter Off-Peak (1,917 hours)	19,170	0.03	479,250
Total	**575,505**		**35,245,125**

[13] *For sophisticated methods, this calculation may be a direct output of the modeling exercise.*

Sophisticated Methods for Estimating Short-Run Avoided Costs: Economic Dispatch Modeling

Sophisticated simulation modeling, such as simulation of economic dispatch decisions, automatically applies the four steps described above. It uses a detailed representation of the electricity system based upon a wide range of assumptions about technology characteristics and operation. Economic dispatch models (also commonly referred to as "production costing" models) incorporate load duration curves as described in the basic methods section previously, and calculate the types of generation necessary to meet demand for different deployment scenarios of energy efficiency and renewable energy. While developing a full input dataset for an economic dispatch simulation model can be a resource-intensive task, the output from a simulation model can provide more valid estimates than a basic-to-intermediate method, especially for energy efficiency and renewable energy resources with more availability at certain times and for projections of energy efficiency and renewable energy impacts in the future.

Economic dispatch models can also be employed to develop parameters that can be used to estimate the impacts of a large range of energy efficiency and renewable energy resources. For example, multiple model runs can be performed to estimate the impacts of changes in generation requirements at different seasons and times of day (e.g., winter peak, summer peak, base, etc.). These parameters, such as the marginal emissions rate and avoided costs, then can be applied to estimate of the impacts of energy efficiency and renewable energy resources at those same times.

Economic dispatch models simulate the dynamic operation of the electricity system given the characteristics of specific generating units and system transmission constraints. They typically do not predict how the electricity system will evolve but instead can indicate how the electricity system is likely to respond to a particular energy efficiency or renewable energy policy or measure. This is appropriate in the short run when the electricity system is more likely to react than to evolve due to energy efficiency and renewable energy measures. Economic dispatch models specifically replicate least-cost system dispatch and can be used to determine which generating units are displaced and when they are displaced based on economic and operating constraints.

Generally, this method involves modeling electricity dispatch without the new resource BAU case and then modeling dispatch with the new resource, on an hourly basis and typically for 1 to 5 years into the future. As with basic-to-intermediate estimation methods, it is essential to establish the specific operational profile of the energy efficiency or renewable energy resource. An hourly economic dispatch model can be used to determine hourly marginal costs and emissions rates (lbs./kWh), which can then be aggregated by time period and applied to a range of energy efficiency and renewable energy resources according to their production characteristics. Some models, described later in this chapter, simulate both capacity planning and dispatch although they may have a simpler representation of dispatch (e.g., seasonally, with multiple load segments). These models function in the same way as economic dispatch models that do not address capacity planning, but offer the ability to capture the differing marginal resources over load levels and time. Analysts can also use capacity expansion model outputs (e.g., related to expectations about new and retired units) as inputs to economic dispatch models that do not already address capacity planning to adjust the fleet of generation units and run detailed analyses. See the box "NREL Eastern Renewable Generation Integration Study" for an example.

When to use: Hourly economic dispatch modeling is generally used for near-term, highly detailed estimations. This method is appropriate for financial evaluations of specific projects, short-term planning, and regulatory proceedings. Sensitivity cases can be examined to explore

NREL EASTERN RENEWABLE GENERATION INTEGRATION STUDY

NREL's Eastern Renewable Generation Integration Study (ERGIS) analyzed the impacts of four wind and PV scenarios in the Eastern Interconnection region and found that integration of 30 percent renewables is technically feasible at a 5-minute interval. NREL used a combination of capacity expansion and economic dispatch modeling, using the ReEDS capacity expansion model to project future capacity additions to the grid. Once capacity additions and retirements were determined, NREL incorporated these results into PLEXOS, an economic dispatch model, to perform high-resolution economic dispatch modeling of the Eastern Interconnection, model the interactions of 5,600 generating units and over 60,000 transmission nodes at 5-minute intervals.

Source: NREL, 2016

how impacts respond to changes in input assumptions and scenario analysis can be conducted to more fully understand the range of impacts. While economic dispatch modeling is generally seen as very credible in these contexts, because of the limitations described below, agencies and stakeholders often rely on the results of economic dispatch modeling conducted by utilities and their consultants for regulatory proceedings rather than running dispatch models themselves.

Strengths of economic dispatch models:

- *Capture a high level of detail:* These models provide forecasts of wholesale electric prices for each hour (i.e., system marginal costs) and the hourly operations of each unit, typically up to a 5-year timeframe. This information has been the basis for plant financing decisions and the development of unit operating and bid strategies in markets. These same data also are necessary in estimating the emissions of specific units and the regional electricity system being modeled. By comparing the variable costs of each unit with the price forecasts, an analyst can estimate plant profitability.
- *Can run multiple cases:* Once the effort is taken to establish a BAU case, the incremental effort to add each additional sensitivity case is lower than establishing the BAU case. Running multiple cases can build up a range of impacts on various planning parameters (e.g., transmission, plant dispatch, and avoided variable costs), and may capture complex interactions and tradeoffs between these cases that basic approaches cannot.
- *Capture detailed operational and variable costs:* They are usually more detailed in their specification of operational and variable costs compared with capacity expansion models.

Limitations of economic dispatch models:

- *Do not capture avoided capacity costs:* Unlike capacity expansion models described later in this chapter, economic dispatch models cannot estimate avoided capacity costs from energy efficiency or renewable energy investments. These costs must be calculated outside the economic dispatch model using a spreadsheet model or other calculations.
- *Have significant data requirements to set up and run:* Some of these models require substantial detail on each unit in a regional electricity system and are typically full chronologic models (i.e., some data elements are needed for all 8,760 hours in a year). These models can also be labor-, time-, and cost-intensive.
- *Lack transparency:* Models may lack transparency. For example, economic dispatch models vary in terms of how they treat outage rates, heat rates, bidding strategies, transmission constraints, and reserve margins. Underlying assumptions about these factors may not be apparent to the model user, interested stakeholders, or an analyst examining the results.

Basic-to-intermediate and sophisticated methods each have strengths and limitations, as is illustrated in Table 3-4. Analysts can use these comparisons to help them determine the most appropriate method for their particular goals.

Table 3-4: Comparison of Basic-to-Intermediate and Sophisticated Methods for Quantifying Short-Run Avoided Costs of Electricity Generation or Wholesale Electricity Purchases

Methods	Strengths	Limitations	When to Use This Method	Tools
Basic-to-Intermediate Methods				
▪ System Average ▪ Proxy Plant ▪ Capacity Factor (i.e., Displacement Curve Analysis) ▪ Dispatch Curve Analysis	▪ Are simple ▪ May already be available	▪ Combine electricity use and capacity ▪ Not always relevant to a given policy if timing or costs are different ▪ Limited horizon (futures) ▪ May miss interactive effects (fuel and emissions markets) and reductions outside region of interest for significant energy efficiency and renewable energy investments over time	▪ When time, budget, and data are limited ▪ For rough estimates ▪ For preliminary assessments ▪ For overview-type policy assessments ▪ For small programs	▪ N/A
Sophisticated Method				
▪ Economic Dispatch Modeling[a]	▪ Represents electricity dispatch robustly and realistically ▪ Captures a high level of detail (e.g., operational and variable costs) ▪ Can run multiple scenarios (e.g., sensitivities)	▪ Is cost-intensive ▪ Is data- and time-intensive ▪ Is not transparent ▪ Does not capture avoided capacity costs	▪ When sufficient time, budget, and data resources are available ▪ When high degree of precision and analytic rigor is required ▪ When energy efficiency or renewable energy resource use will change system operations (e.g., energy efficiency and renewable energy resources change the marginal generating resource in a large number of hours)	▪ GE MAPS™ ▪ IPM® ▪ PLEXOS® ▪ PROMOD IV® ▪ PROSYM™

[a] *Economic Dispatch Modeling refers to unit commitment, security constrained unit commitment, and production cost models.*

Long-Run Avoided Costs of Power Plant Capacity

While the avoided cost of electricity generation is the major short-run benefit, avoided costs of adding new power plant capacity in the long run (typically 5 or more years) can be significant and are an important consideration for resource decisions.[14] For example, in the short run, energy efficiency and renewable energy policies and programs can enable electricity generators to operate less frequently and avoid fuel and variable O&M costs, or sell surplus generation capacity to other utilities in the region to meet their capacity needs. Over the long run, however, new energy efficiency and renewable energy initiatives typically avoid or defer both the cost of building new power plants and the cost of operating them.

[14] *For more information about establishing energy efficiency as a high-priority resource in long-term planning, see* National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change, *November 2008.* https://www.epa.gov/sites/production/files/2015-08/documents/vision.pdf.

Methods for Estimating Long-Run Avoided Costs of Power Plant Capacity

The avoided cost of building and operating new power plants are the avoided costs of power plant capacity that can be estimated using either basic estimation or sophisticated simulation methods, each of which has strengths and limitations.[15]

Basic Methods for Estimating Long-Run Avoided Costs of Power Plant Capacity

Basic estimation methods involve the use of tools such as spreadsheets to estimate any long-run avoided costs of power plant capacity that may result due to an energy efficiency or renewable energy measure under consideration. One method for quantifying long-term savings of energy efficiency and renewable energy measures, the proxy plant method, relies on selecting a unit type as a proxy to represent the avoided costs of building future generating capacity.

Proxy Plant Method

Similar to how a proxy plant could be used to represent displaced generation from existing plants when estimating short-run avoided costs (i.e., Basic Method 2: Proxy Plant), an analyst can use a proxy plant method to estimate the costs that can be avoided in the long run by avoided the construction of a power plant in the future. Over the long term, proxy plant assessments are typically done using cost assumptions for the expected next addition.

Electricity cost estimates in this basic method would use a proxy plant's dispatch costs for future estimates and the capital costs. Depending on future expectations of capital costs, fuel prices, and environmental requirements, state policy makers can choose from a variety of generating units to represent their proxy plant. EPA has observed that many states use natural gas combustion turbines to represent the long-run avoided costs of electricity and capacity of energy efficiency and renewable energy initiatives. Forward capacity markets provide another resource for power plant capacity pricing expectations that may be integrated into these basic methods, as the results of their auctions should represent the market's opinion of future capacity costs in the region.

Data required for this method include:

- Cost and performance information for the proxy plant
- Capital cost escalation rates, a discount rate, and other financial data

See Section 3.4., "Tools and Resources," for potential data sources.

[15] *For more information about how utilities estimate avoided costs, see* The Guide to Resource Planning with Energy Efficiency: A Resource of the National Action Plan for Energy Efficiency, *November 2007,* https://www.epa.gov/sites/production/files/2015-08/documents/resource_planning.pdf.

USING PROXY POWER PLANT DATA TO ESTIMATE AVOIDED CAPITAL COSTS

To estimate avoided capital costs of an energy efficiency or renewable energy resource, a discounted cash flow analysis can first be conducted using data on initial construction costs, fixed and variable operating costs, and financial data. Once estimated, the NPV of the cost of owning the unit that reflects the full carrying costs of the new unit (including interest during construction, debt servicing, property taxes, insurance, depreciation, and return to equity holders) can be converted to annualized costs. The equation for calculating annual avoided capital costs is:

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

The load profile information (reductions in demand at peak hours), discussed earlier would provide an estimate of displaced capacity, or simpler estimates can be used.

NREL's Jobs and Economic Development Impact (JEDI) model (http://www.nrel.gov/analysis/jedi/) is a free tool designed to allow users to estimate the economic costs and impacts of constructing and operating power generation assets. The tool provides plant construction costs, as well as fixed and variable operating costs. The following example shows avoided capital costs for an energy efficiency or renewable energy program that avoids the construction of a natural gas combustion turbine with the following characteristics:

- Construction cost = $1,250/kW
- Annual operation cost = $8.25/kW
- Energy efficiency program savings = 500 MW

The program would realize the following benefits:

- Avoided plant construction cost = $648 million
- Annual operating cost savings = $177 million

Source: NREL, 2015.

Sophisticated Methods for Estimating Long-Run Avoided Costs of Power Plant Capacity: Capacity Expansion Models

Sophisticated simulation methods, such as capacity expansion models (also called system planning models), can be used to quantify the long-run avoided capacity costs that result from implementing energy efficiency and renewable energy measures. Capacity expansion models project how the electricity system is likely to evolve over time, including what capacity will likely be added through the construction of new generating units and what units will likely be retired, in response to changes in demand and prices. Forecasts are based on numerous factors, including but not limited to: the costs of new technology, expected growth in electricity demand and changes in prices, regional electricity system operations, existing fleet of generating assets, the characteristics of candidate new units, environmental regulations (current and planned), and the deployment of energy efficiency and renewable energy measures. Models use this type of information, typically within an optimization framework, to select a future build-out of the system (e.g., multiple new units over a multi-decadal time frame) that has the lowest overall NPV, considering both capacity and variable costs of each unit.

Typical steps involved in estimating the avoided costs of power plant capacity using capacity expansion models:

1. Generate a BAU forecast of load and how it will be met.
2. Include the energy efficiency or renewable energy resource over the planning period and create an alternative forecast.
3. Calculate the avoided costs of power plant capacity.

Step 1: Generate a BAU Forecast of Load and How It Will Be Met

Some capacity expansion models use existing generating plants and purchase contracts to meet projected electricity demand over the forecast period, and the model (or the analyst) adds new generic plants when those resources do not meet the load forecast. The type of plants added depends on their capital and operating costs, as well as the daily and seasonal time-pattern of the need for power determined over the forecast period. Using these cost and time characteristics, the NPV of adding various power plant types can be compared using discounted cash flow analysis as mentioned earlier in the box "Using Proxy Power Plant Data to Estimate Avoided Capital Costs." Sophisticated capacity expansion models will run through an optimization process that chooses the least-cost solution to adding capacity. The model repeats this process until the load is served through the end of the forecast period and a least-cost solution is found. This BAU scenario contains a detailed schedule of resource additions that becomes the benchmark capital and operating costs over the planning period for later use in the long-run avoided cost calculation.

Step 2: Include the Energy Efficiency or Renewable Energy Resource Over the Planning Period and Create an Alternate Forecast

The following two methods can be used to incorporate the energy efficiency resource into the second projection:

- For a more precise estimate of the savings from an energy efficiency program, reduce the load forecast year-by-year and at more granular time-scales (e.g., daily or hourly) to capture the impact of energy efficiency resource, based on the program design and estimates of its electricity and capacity savings. This method would capture the unique load shape of the energy efficiency resource.
- For a less rigorous estimate (e.g., to use in screening candidate energy efficiency policies and programs during program design), reduce the load forecast by a fixed amount in each year, proportionally to load level. This method does not capture the unique load shape of the energy efficiency resource.

For renewable energy resources, add the resource to the supply mix. For some models and non-dispatchable resources, including distributed renewable energy resources, renewable energy could be netted from load in the same manner as is done for energy efficiency in the second bullet above.

Step 3: Calculate the Avoided Costs of Power Plant Capacity

The difference between the costs in the two projections created in Steps 1 and 2 represents the annualized or NPV costs that would be avoided by the energy efficiency or renewable energy resource. If a per unit avoided cost, such as the avoided cost per Megawatt-hour (MWh), is needed for screening energy efficiency and renewable energy resources or other purposes, it may be computed by taking the avoided cost (i.e., the difference between the cost in the two projections) for the relevant time period (e.g., a given year) and dividing that by the difference in load between the two projections. As noted above, analysts should compare the costs of implementing energy efficiency and renewable energy measures against the calculated avoided costs to understand the net cost or benefit of those measures

When to use: Capacity expansion or system planning models are typically used for longer-term studies (typically 5 to 40 years) where the impacts are dominated by long-term investment and retirement decisions. They are often used to evaluate large geographic areas and can examine potential long-term impacts on the electric sector or upon the entire energy system (e.g., fuels and emissions markets), which could also include the industrial, residential, commercial, and transportation sectors. In contrast, economic dispatch models focus on only the electricity sector.

Energy system capacity expansion models are generally used for projecting scenarios of how the energy system will adapt to changes in supply and demand or to new policies including emissions controls. They may consider the complex interactions and feedbacks that occur within the entire energy system, rather than focusing solely upon the electric sector impacts. This is significant because there can be tradeoffs and cross sector interactions that may not be captured by a model that focuses solely on the electricity sector. In addition to capturing the numerous interactions, energy system capacity expansion models can also model dispatch, although often not in as sophisticated a manner as a dedicated economic dispatch model (e.g., in a chronological, 8,760-hour dispatch).[16]

[16] For more information about using capacity expansion models to estimate air and greenhouse emissions from energy efficiency and renewable energy initiatives, please see Section 4.2.2, "Step 2: Quantify Expected Emissions Reductions."

Strengths of capacity expansion models:

- *Capture complex interactions:* They may capture the complex interactions and feedbacks that occur within the entire energy system, including many factors that are influenced by changing policies, regulatory regimes, or market dynamics (e.g., stricter emissions policy, introduction of a renewable portfolio standard).
- *Are designed for resource planning:* While both economic dispatch models and capacity expansion models are used in utility integrated resource planning proceedings, capacity expansion models are designed specifically for resource planning.
- *Capture avoided costs:* Capacity expansion models are able to estimate avoided capacity costs and usually also produce estimates of avoided variable costs.
- *Show system adaptability:* They can show how the electricity system is likely to adapt in response to new policies.
- *Cover a long timeframe:* The model selects optimal changes to the resource mix based on energy system infrastructure over the long term (typically 5 to 40 years).
- *Provide emissions reductions:* They provide estimates of emissions reductions from changes to generation mix.
- *Can layer in dispatch characteristics:* Some capacity expansion models may provide plant-specific detail and perform dispatch simultaneously (IPM).

Limitations of capacity expansion models:

- *Require many assumptions:* They require assumptions that have a large impact on outputs (e.g., future fuel costs). It is imperative to carefully consider key assumptions, such as fuel price forecasts and retirements, and the ability to accurately model the complex factors affecting the system including environmental and other regulatory requirements (e.g., renewable portfolio standards). These assumptions point to the need for model validation or calibration against actual data or another projection model. Most of the models are supported by their developers or other consultants who have available datasets. Some studies calibrate against the National Energy Modeling System (NEMS)-generated AEO produced by U.S. DOE's EIA.
- *Require technical expertise:* Capacity expansion models may require significant technical experience to run.
- *Lack transparency:* They often lack transparency due to their complexity and proprietary nature.
- *May require significant labor, time, and financial resources:* These types of models can be labor- and time-intensive, and may have high labor and software licensing costs.

Table 3-5 provides a simple comparison of the methods for estimating long-run avoided costs of power plant capacity.

Table 3-5: Comparison of Basic and Sophisticated Methods for Quantifying Long-Run Avoided Costs of Power Plant Capacity

Methods	Strengths	Limitations	When To Use This Method	Tools / Examples
Basic				
▪ Proxy Plant	▪ Are simple ▪ May provide cost assumptions	▪ Do not reflect opportunities to displace conventional baseload units in the long run	▪ For rough estimates ▪ For preliminary screening of demand response resources ▪ For overview-type policy assessments	▪ Natural gas combustion turbine (proxy plant method)
Sophisticated				
▪ Capacity expansion models	▪ Capture complex interaction to provide a robust representation of electrical system operation ▪ Are designed for resource planning ▪ Capture avoided costs ▪ Show system adaptability ▪ Cover a long timeframe ▪ Provide emissions reductions ▪ Can layer in dispatch characteristics	▪ Require many assumptions ▪ Require technical expertise ▪ Lack transparency ▪ May require significant labor, time, and financial resources	▪ When energy efficiency or renewable energy resource use will impact generation and investment in the capacity mix (e.g., resources avoid or defer building new power plants and operating them a large number of hours)	▪ AURORA ▪ U.S. DOE's NEMS ▪ EGEAS ▪ e7 Capacity Expansion Strategist ▪ e7 Portfolio Optimization ▪ Energy 2020 ▪ LEAP ▪ IPM® ▪ MARKAL, TIMES ▪ NREL's ReEDS ▪ NREL's RPM

Transmission and Distribution Benefits

In addition to avoiding electricity generation and power plant capacity additions, energy efficiency and renewable energy policies and programs that affect customers at the end-use (e.g., through residential or commercials measures) can help to avoid electricity losses during T&D and also avoid the capacity costs of building new T&D capacity. The following sections describe methods for quantifying these benefits.

Avoided Electricity Losses During Transmission and Distribution

Avoided T&D losses from energy efficiency and renewable energy policies and programs can be estimated by multiplying the estimated electricity and capacity savings located near or at a customer site by the T&D loss factor (i.e., the percent difference between the total electricity supplied to the T&D system and the total electricity taken off the system for delivery to end-use customers during a specified time period). A method for determining T&D losses is described below.

The two different types of T&D loss factors are generation-based factors and consumption-based factors. A generation-based factor is determined based on losses experienced at the individual generating facilities whereas consumption-based factors are calculated based on losses that occur throughout the generation, transmission, and distribution process, from the generation of the electricity to its point of consumption. A consumption-based T&D loss factor is appropriate to use for energy efficiency and distributed renewable energy programs a capture the T&D losses throughout the system.

A consumption-based T&D loss factor can be calculated using the following formula:

> *(Net Generation to the Grid + Net Imports – Total Electricity Sales) / Total Electricity Sales*

T&D losses in the range of 6 to 10 percent are typical, which means that for every 1 kWh saved at the customer's meter, 1.06–1.10 kWh are avoided at the generator. EIA estimates that the average consumption-based U.S. T&D loss factor was 8.38 percent in 2016 (EIA, 2018).[17] See Section 3.4., "Tools and Resources," for data sources that can be used to calculate a consumption-based T&D loss factor.

EXAMPLE OF T&D LOSS CALCULATIONS

Suppose a PG&E utility end-use energy efficiency program saves 500 MWh during the summer months of a given year.

In 2017, the CPUC calculated PG&E's generation to meter loss factors for summer peak and off-peak as 1.109 and 1.057, respectively (E3, 2017). Therefore, if 30 percent of energy is consumed during summer peak hours and 70 percent is consumed during summer off-peak hours, then the program savings during summer would total 536.3 MWh (1.109 * 30% * 500 MWh + 1.057 * 70% * 500 MWh).

T&D losses are typically higher when load is higher, especially at peak times when losses can be as great as twice the average value. The T&D loss reductions from energy efficiency, load control, and distributed generation are thus significantly higher when the benefits are delivered on peak than when they occur at average load levels, which greatly enhances the reliability benefits. The California Public Utilities Commission (CPUC) calculated the value of deferring T&D investments adjusted for losses during peak periods using the loss factors shown in Table 3-6 and Table 3-7 (E3, 2017). For example, an energy efficiency measure that saves 10.0 kWh of power at an SDG&E customer's meter would save 10.71 kWh once a T&D loss factor of 1.071 is factored in.

The significance of T&D losses in high load periods is further increased by the high marginal electricity costs and electricity prices experienced at those times. Due to the variation in loads over the course of the year, T&D loss estimates are more precise when developed for short time periods (e.g., less than 1 year).

Utilities routinely collect average annual energy loss data by voltage level (as a percentage of total sales at that level). RTOs and ISOs also provide loss data. Note that transmission loss, which is smaller than distribution loss, may be included in wholesale electricity prices in restructured markets.

Estimates of T&D losses can be applied to the electricity impacts estimated as described in Chapter 2, "Estimating the Direct Electricity Impacts of Energy Efficiency and Renewable Energy." If load profile information is available, then estimates can be used to distinguish between higher on-peak loss rates and lower off-peak loss rates. Once the total electricity impact is determined, see "Generation Benefits: Avoided Costs" in Section 3.2.4., Methods for Quantifying Primary Electricity System Benefits, for calculating avoided costs of generation from electricity impacts.

Table 3-6: Loss Factors for SCE and SDG&E T&D Capacity

	SCE	SDG&E
Distribution Only	1.022	1.043
T&D	1.054	1.071

Source: E3, 2017.

[17] *EIA also uses an alternative, generation-based method for calculating T&D losses that results in lower percentages (typically around 5 percent) based on losses reported at the individual facility level by utilities; see https://www.eia.gov/tools/faqs/faq.cfm?id=105&t=3 for details. Using this method as opposed to a consumption-based method would underestimate the T&D loss benefits of energy efficiency initiatives.*

Table 3-7: Loss Factors for PG&E T&D Capacity

	T&D	Distribution Only
Central Coast	1.053	1.019
De Anza	1.050	1.019
Diablo	1.045	1.020
East Bay	1.042	1.020
Fresno	1.076	1.020
Kern	1.065	1.023
Los Padres	1.060	1.019
Mission	1.047	1.019
North Bay	1.053	1.019
North Coast	1.060	1.019
North Valley	1.073	1.021
Peninsula	1.050	1.019
Sacramento	1.052	1.019
San Francisco	1.045	1.020
San Jose	1.052	1.018
Sierra	1.054	1.020
Stockton	1.066	1.019
Yosemite	1.067	1.019

Source: E3, 2017.

Avoided Transmission and Distribution Capacity Costs

Energy efficiency and renewable energy policies and programs that affect areas that are sited on or near a constrained portion of the T&D system can potentially:

- Avoid or delay costly T&D upgrades, construction, and associated O&M costs, including cost of capital, taxes and insurance.
- Reduce the frequency of maintenance, because frequent peak loads at or near design capacity will reduce the life of some types of T&D equipment.

Deferral of T&D investments can have significant economic value. The value of the deferral is calculated by looking at the present value difference in costs between the transmission project as originally scheduled and the deferred project. Most often, the deferred project will have a slightly higher cost due to inflation and cost escalations (e.g., in raw materials), but can have a lower present value cost when the utility discount rate is considered (which affects the utility's cost of capital). The difference in these two factors determines the value of deferring the project.

The avoided costs of T&D capacity vary considerably across a state depending on geographic region and other factors. Table 3-8 and Table 3-9 were developed for the CPUC in 2017 and illustrate how avoided costs of T&D capacity vary in California (in $/kW-year) by utility and climate zone. Using avoided cost estimates based on these differences, rather than on statewide system averages, enables state decision makers to better target the design, funding, and marketing of their energy efficiency and renewable energy actions (E3, 2017).

Table 3-8: 2016 Avoided T&D Capacity Costs for SCE and SDG&E

	SCE	SDG&E
Sub-transmission ($/kW-yr)	$30.52	–
Substation ($/kW-yr)	–	$22.05
Local distribution ($/kW-yr)	$101.90	$77.97

Source: E3, 2017.

Note: SCE capacity costs are based on 2015 filed values with 2 percent per year inflation. Sub-transmission lines are the part of the grid that interconnects the bulk transmission elements with the distribution elements and transfer electricity at lower voltages than transmission lines, while substations are used to scale up or down the voltage of power as it moves along the electricity system.

Table 3-9: 2016 T&D Capacity Costs for PG&E

Division	Climate Zone	Transmission $/kW-yr	Primary Distribution $/kW-yr	Secondary Distribution $/kW-yr
Central Coast	4	$36.27	$99.31	$8.19
De Anza	4	$36.27	$117.26	$4.66
Diablo	12	$36.27	$54.69	$7.43
East Bay	3A	$36.27	$62.73	$3.34
Fresno	13	$36.27	$31.53	$3.96
Kern	13	$36.27	$32.70	$4.50
Los Padres	5	$36.27	$42.52	$5.25
Mission	3B	$36.27	$20.67	$3.42
North Bay	2	$36.27	$18.46	$4.65
North Coast	1	$36.27	$43.93	$7.18
North Valley	16	$36.27	$37.52	$8.47
Peninsula	3A	$36.27	$40.18	$6.12
Sacramento	11	$36.27	$39.17	$4.37
San Francisco	3A	$36.27	$19.07	$2.62
San Joe	4	$36.27	$40.06	$5.06
Sierra	11	$36.27	$30.88	$6.77
Stockton	12	$36.27	$39.81	$4.72
Yosemite	13	$36.27	$47.63	$7.45

Source: E3, 2017.

Note: PG&E capacity costs are based on 2014 filed values with 2 percent per year inflation and peak capacity allocation factor. Primary distribution refers to the part of the distribution network that can deliver power to larger commercial and industrial users and operates with voltage levels in the tens of kilovolts. Secondary distribution refers to the lowest voltage level along the grid that delivers electricity directly to households and small commercial customers.

The benefit of avoided T&D costs is often overlooked or addressed qualitatively in resource planning because estimating the magnitude of these costs is typically more challenging than estimating the avoided costs of electricity generation and plant capacity. For example, the avoided T&D investment costs resulting from an energy efficiency or renewable energy program are highly location-specific and depend on many factors, including the current system status, the program's geographical distribution, and trends in customer load growth and load patterns. It is also difficult to estimate the extent to which energy efficiency and renewable energy measures would avoid or delay expensive T&D upgrades, reduce maintenance, and/or postpone system-wide upgrades, due to the complexity of the system.

Methods for Estimating Avoided Transmission and Distribution Capacity Costs

A common method to estimate avoided T&D costs is the system planning method. The system planning method uses projected costs and projected load growth for specific T&D projects based on the results from a system planning study—a rigorous engineering study of the electricity system to identify site-specific system upgrade needs. Other data requirements include site-specific investment and load data. This method assesses the difference between the present value of the original T&D investment projects and the present value of deferred T&D projects.[18] The system planning method uses projections and thus can consider future developments.

Projected embedded analysis is another method used to estimate avoided T&D costs. According to a New York State Energy Research and Development Authority (NYSERDA) report, to use this method, "utilities use long-term historical trends (more than 10 years) and sometimes planned T&D costs to estimate future avoided T&D costs. This approach often looks at load-related investment (as opposed to customer-related) and estimates system-wide (e.g., utility service territory) average avoided T&D costs" (NYSERDA, 2011).

The difference between the two methods is that projected embedded analysis provides a system average view, whereas the system planning method provides project-specific estimates. If analysts want to assess avoided costs for the system generally, projected embedded analysis will provide that information. However, this method will not be able to assess the impact of specific projects. To do that, analysts will need the system planning method.

CON EDISON EXPANDS ITS NON-WIRES ALTERNATIVES PROGRAM TO REDUCE LOAD

In December 2014, state regulators approved Con Edison's Brooklyn/Queens Demand Management (BQDM) Program to address a forecasted overload condition of the electric sub-transmission feeders serving two of their substations. The program is designed to reduce load by contracting for 41 MW of customer-side solutions and 11 MW of non-traditional utility-side solutions, such as distributed resource investments. Con Edison's operating budget for the program is $150 million and $50 million for the two different solutions, respectively.

Since launching the program, Con Edison has deferred a $1.2-billion substation upgrade by employing a strategy that harnesses a range of distributed resources and efficiencies rather than spending ratepayer funds on conventional utility solutions, such as construction of new substations and sub-transmission feeders. As of summer 2018, Con Edison had contracted for more than 52 MW of non-traditional solutions. The project was deemed successful and was re-authorized for extension by state regulators in July 2017. The extension allows the utility to obtain further demand reductions and defer additional traditional infrastructure investments, without any additional funding.

Sources: Con Edison, 2017; State of New York Public Service Commission, 2017.

Generally, it is difficult to be precise when calculating the avoided cost of T&D capacity because costs are very site specific and their quantification involves detailed engineering and load flow analyses. Other factors affecting location-specific T&D project cost estimates are system congestion and reliability.

During periods of high congestion, for example, interconnected resources that can be dispatched at these specific times are credited at time-differentiated avoided costs. In addition to region-specific annual avoided T&D capacity costs shown above in Table 3-8 and Table 3-9, the CPUC also uses time-differentiated avoided T&D capacity costs to estimate long-run avoided costs to support analyses of the cost-effectiveness of energy efficiency measures. For example, according to the CPUC, measures that reduce electricity consumption in August can have more than four times the

[18] The investment in nominal costs is based on revenue requirements that include cost of capital, insurance, taxes, depreciation, and O&M expenses associated with T&D investment (Feinstein et al., 1997; Orans et al., 2001; Lovins et al., 2002).

avoided costs of those that occur in January, due to the benefits of reducing peak demand during normally congested summer months. Furthermore, energy efficiency measures that reduce electricity consumption during hours of peak demand, such as mid- to late-afternoon, can potentially incur more than $10,000/MWh more in avoided costs than those that occur during non-peak times (depending on energy market prices) (E3, 2017).

Summary of Primary Electricity System Benefits

Table 3-10 outlines some of the factors that state decision makers can consider when deciding which primary electricity system benefits to analyze, including available methods and examples, strengths, limitations, and purpose of analysis.

Table 3-10: Primary Electricity System Benefits from Energy Efficiency and Renewable Energy Measures

Applicable Energy Efficiency and Renewable	Considerations for Determining Whether to Analyze	Who Usually Conducts, Commissions, or Reviews an Analysis?	When Is Analysis Usually Conducted or Made Available?
BENEFIT: Avoided electricity generation or wholesale electricity purchases			
▪ All resources ▪ Resources that operate during peak hours	▪ Traditionally analyzed in cost-benefit analysis ▪ Widely accepted methods ▪ Data generally available but expensive ▪ Sophisticated models available but complex, not transparent, and often expensive to use ▪ Many assumptions about technology, costs, and operation needed ▪ Long-term fuel price forecasts can be obtained from EIA's AEO, developed internally, or purchased	▪ Utilities conduct in-depth modeling ▪ State utility regulatory commissions and other stakeholders review utility's results and/or conduct own analysis ▪ RTO/ISO and the Independent Market Monitor conduct own analyses for planning, demand response programs, and market intelligence ▪ EIA and private consultancies provide economic dispatch and capacity expansion forecasts	▪ Resource planning and released regulatory proceedings ▪ Area-specific DSM program development ▪ RTO/ISO avoided cost estimates may be published on regular schedules
BENEFIT: Avoided power plant capacity additions			
▪ All resources ▪ Resources that operate during peak hours	▪ Traditionally analyzed in cost-benefit analysis ▪ Generally accepted methods for both estimation and simulation ▪ Some assumptions about technology, costs, and operation needed ▪ Data generally available	▪ Utilities conduct in-depth modeling ▪ State utility regulatory commissions and other stakeholders review utility's results and/or conduct own analysis ▪ RTO/ISO may publish capacity clearing prices ▪ EIA and private consultancies provide capacity expansion forecasts	▪ Resource planning and released regulatory proceedings ▪ Area-specific DSM program development ▪ RTO/ISO avoided cost estimates may be published on regular schedules
BENEFIT: Avoided T&D losses			
▪ Resources that are close to load, especially those that operate during peak hours	▪ Traditionally analyzed in cost-benefit analysis ▪ Straightforward; easy to estimate once avoided electricity has been calculated ▪ Loss factor for peak savings may need to be estimated	▪ Utilities collect loss data regularly and may conduct in-depth modeling ▪ State utility regulatory commissions and other stakeholders review utility's results and/or conduct own analysis	▪ Resource planning and released regulatory proceedings ▪ Area-specific DSM program development

Applicable Energy Efficiency and Renewable	Considerations for Determining Whether to Analyze	Who Usually Conducts, Commissions, or Reviews an Analysis?	When Is Analysis Usually Conducted or Made Available?
BENEFIT: Deferred or avoided T&D capacity			
▪ Resources that are close to load, especially those that operate during peak hours	▪ Traditionally analyzed in cost-benefit analysis ▪ Load flow forecast availability ▪ Unit cost of T&D upgrades can be estimated but may be controversial ▪ T&D capacity savings reasonably practical, but site-specific savings difficult to generalize	▪ Utilities conduct in-depth modeling ▪ State utility regulatory commissions and other stakeholders review utility's results and/or conduct own analysis ▪ RTO/ISO conduct own analyses for planning or reports	▪ T&D build planning ▪ Area-specific DSM program development ▪ RTO/ISO cost estimates may be published on regular schedules

3.2.5. Methods for Quantifying Secondary Electricity System Benefits

Energy efficiency and renewable energy policies and programs result in many additional electricity system benefits that affect the efficiency of electricity systems and energy markets, including:

- Avoided ancillary services costs
- Reductions in wholesale market clearing prices
- Increased reliability and power quality
- Avoided risks associated with long lead-time investments, such as the risk of overbuilding the electricity system
- Reduced risks from deferring investment in conventional, centralized resources pending uncertainty in future environmental regulations
- Improved fuel diversity
- Improved energy security

These secondary benefits have associated cost reductions, but the methodologies for assessing them are sometimes diverse, qualitative, and subject to rigorous debate.

The ability to estimate the secondary benefits of energy efficiency and renewable energy policies and programs and the availability of methods vary depending on the benefit. These methods are less mature than those for primary benefits, and as such, they tend to rely more on non-modeling estimation methods than do more sophisticated simulation models. Secondary electricity system benefits, and methods for estimating them, are described below.

Avoided Ancillary Services Costs

"Ancillary services" is a catchall term for electric generator functions needed to ensure reliability, as opposed to providing power, and include services such as operating reserves, voltage support, and frequency regulation.

RTOs and ISOs routinely report market prices for ancillary services such as voltage support and frequency regulation. In those regions with ancillary service markets, such as PJM, NYISO, ISO-NE, ERCOT, and the California ISO, services are provided at rates determined by the markets and thus are easily valued.[19] The avoided costs of ancillary services are typically smaller than other costs, such as avoided electricity, capacity, and T&D investment. For example, 2017 voltage support services were only 0.77 percent of the total PJM wholesale cost (PJM, 2018).

ANCILLARY SERVICES THAT ENERGY EFFICIENCY AND RENEWABLE ENERGY RESOURCES CAN PROVIDE TO THE SYSTEM

Operating Reserve – Spinning: Generation synchronized to the grid (i.e., "spinning") and usually available within 10 minutes to respond to a contingency event. For example, 50 MW of spinning operating reserve means that a generation unit can increase its output by 50 MW within 10 minutes.

Operating Reserve – Supplemental: Generation that is available within 30 minutes but is not necessarily synchronized to the grid.

Voltage Support: For reliable electricity flow on the transmission system, voltage must be maintained within an acceptable range. Voltage is regulated by reactive power which is absorbed or generated by different power system assets such as capacitors or generators.

Frequency Regulation: The ability to control the alternating current (AC) frequency so that it remains within a tolerance bound. Control can be maintained with generator inertia, ramping generation up or down, demand response, or storage.

Operating Reserves

Operating reserves are generation resources available to meet loads quickly in the event a generator goes down or some other supply disruption occurs. Energy efficiency programs avoid the need to procure additional capacity for operating reserves. Whereas energy efficiency programs typically do not affect the procurement of resources for operating reserves in the short term, they can affect long-run costs of avoiding building capacity to meet operating reserve requirements. The market value of a given MW of energy efficiency or renewable energy short-term reserve is equal to the operating reserve price, as posted by the RTO or ISO on its website. In regions with ancillary service markets, the RTO will set up a market where resources can bid to provide the service. Those that successfully bid are paid the clearing price by the RTO. An increased supply of low-cost energy efficiency will cause ancillary service markets to clear at a lower price. Methods for calculating long-run avoided costs are covered under "Long-Run Avoided Costs of Power Plant Capacity," in Section 3.2.4.

DIRECT EMISSIONS REDUCTIONS FROM DEMAND RESPONSE-PROVIDING ANCILLARY SERVICES

In a 2014 study on CO_2 reductions from demand response, the emissions reductions from demand response-providing ancillary services were estimated for the Electric Reliability Council of Texas (ERCOT). Without demand response, inefficient natural gas peaking units are kept on longer since they are able to respond quickly to sudden shifts in demand. In the ERCOT region, there is only a small amount of coal generation, so peaking units would run in place of more efficient, less polluting NGCC units. Also, the NGCC units would run less efficiently in this case because they would be forced to run at lower than full capacity. With demand response, NGCC units are able to operate at higher capacity levels because demand response resources are able to respond quickly to shifts in demand. This results in CO_2 reductions of greater than 2 percent in each hour where the load exceeds the summer peak average compared to when demand response is not deployed.

In some situations in which renewables need to be curtailed so that sufficient fossil fuel generation is available to provide ancillary services, demand response can instead provide the ancillary services. This prevents the curtailment of renewable resources.

Source: Navigant Consulting, 2014.

[19] *There can be opportunity costs associated with provision of operating reserve. Some regions allow demand response and other energy efficiency and renewable energy resources to bid directly into the electricity market.*

Voltage Support

Maintaining a certain voltage level on the transmission system is necessary to ensure reliable and continuous electricity flow. Electricity system assets, such as capacitors or generators, can help maintain voltage levels by absorbing or generating reactive power, which is a specific and necessary type of power that moves back and forth on the system but is not consumed by load.[20] In electricity markets, market mechanisms compensate utilities for resources that can provide voltage support. The amount of compensation they receive is typically published and can be used by analysts to estimate the avoided cost of voltage support. For instance, to find information on voltage support market mechanisms, analysts can use the reactive power provisions in Schedule 2 of the FERC pro forma open access transmission tariff, or an RTO or ISO's equivalent schedule for reactive support, such as the NY ISO's ancillary service prices for voltage regulation which are published in $/MWh on an hourly basis.[21] Alternately, the difference in reliability with and without the energy efficiency or renewable energy resource can also give some indication of voltage support benefits. (See the reliability metrics discussion in "Increased Reliability and Power Quality," below.)

Some energy efficiency and renewable energy measures can have direct beneficial effects on avoiding certain voltage support (i.e., reactive power) requirements. Reactive power ancillary services are local in nature, and energy efficiency and renewable energy policies and programs that reduce load in a load pocket area can minimize the need for local reactive power requirements. While solar and wind resources may require backup voltage support due to their intermittent nature, demonstrations have shown that large-scale solar PV projects equipped with smart inverters can provide voltage support and other reliability services similar to conventional generating resources (NREL, 2017).

Frequency Regulation

Frequency regulation is necessary to maintain proper grid frequencies within tight tolerance bounds (around 60 Hertz). It involves closely matching the interchange flows and momentary variations in demand within a given control area. Generating units that are ready to increase or decrease power as needed are used for regulation—when a shortfall or excess of generation exists, generation from these units increases or decreases, respectively (U.S. DOE, 2013b). Renewable and demand response resources can support frequency regulation when generating units need to quickly decrease power output. For example, a demand response program that actively reduces load by an end-user through price signals or directives from a master control center can help maintain proper grid frequencies and avoid problems associated with frequency variations below optimal levels (PNNL, 2012). PNNL concluded that proper frequency regulation through demand response can also increase power plant operating efficiencies and help integrate variable renewable energy sources.

COMPLIMENTARY VALUE OF DEMAND RESPONSE FOR VARIABLE RENEWABLE ENERGY

The integration of variable renewable energy can be assisted by demand response services. Increasing amounts of variable renewable energy on a system can increase the need to ramp conventional generating units up and down to meet demand. Demand response can help balance variable renewable energy and provide ancillary services by altering load as needed, reducing the need to ramp up spinning reserves.

Demand-side flexibility is used in practice to provide ancillary services and reliability services. For example, ERCOT obtains half its spinning reserves from demand response. The NYISO has several programs paying for load reductions when the grid is under stress (see http://www.nyiso.com/public/markets_operations/market_data/demand_response/index.jsp).

Source: Bird et al., 2013.

[20] *Two types of power are active power (also called real or true power) and reactive power. Active power, measured in watts, is a function of voltage and current and performs useful work such as powering a lightbulb. In simple direct current (DC) systems, the relationship between voltage and current is constant but in alternating current (AC) systems, such as the power grid, the relationship between voltage and current can change. In order for active power to be consumed, voltage and current must be aligned to produce useful work and it is reactive power that enables this. Reactive power, measured in volt-amp reactive (VAR), is absorbed or produced by certain types of loads, such as motors, and changes the relationship between voltage and current.*

[21] *Note that the Schedule 2 payments are often uniform across a large region. As a result, they may not capture differences in the value of these services in load pockets. For more information about the NY ISO prices, see http://www.nyiso.com/public/markets_operations/market_data/pricing_data/index.jsp.*

Reductions in Wholesale Market Clearing Prices

In addition to the benefits of avoided wholesale electricity costs (i.e., avoided electricity and capacity costs described earlier), energy efficiency and renewable energy resources can lower the demand for electricity or increase the supply of electricity, causing wholesale markets to clear at lower prices, which can benefit consumers.

The methods for estimating short-run wholesale market price effects involve relatively well-understood data and are reasonably straightforward to apply. In contrast, wholesale market price effects over the long term involve relatively poorly understood relationships, and estimating these price effects can become quite complex. For this reason, this section presents the steps involved in estimating the magnitude of the price effects of resource additions in the short run using a basic method. For longer-term forecasts, a more sophisticated method such as an economic dispatch model may be preferred.

Analysts often use Demand Reduction Induced Price Effects (DRIPE) to assess the benefits of a reduction in wholesale market clearing prices from energy efficiency and demand response programs. DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices in a given period. A number of states, including Massachusetts highlighted in the box below, recognize DRIPE as a real, quantifiable benefit of energy efficiency and demand response programs. For instance, an assessment of Ohio's Energy Efficiency Resource Standard showed that program activities for 2014 would result in wholesale price mitigation savings of $880 million and wholesale capacity price savings of $1,320 million for customers through 2020 (SEE Action, 2015).

PRICE EFFECTS OF ENERGY EFFICIENCY PROGRAMS IN THE NORTHEAST IN 2014

A 2015 Avoided-Energy-Supply Component Study (AESC) provides projections of marginal energy supply costs that will be avoided due to reductions in the use of electricity, natural gas, and other fuels resulting from energy efficiency programs throughout New England. AESC projects avoided costs for a future base case in which no new programs are implemented. Demand Reduction Induced Price Effect (DRIPE) refers to the reduction in wholesale market prices for capacity and energy due to energy savings resulting from efficiency and/or demand response programs. Energy reductions from these programs should translate to lower retail rates for customers depending on the T&D network and regulatory framework of the region.

This 2015 study projected the intrastate energy DRIPE in the West Central Massachusetts region in 2015 to be 1.1 cents/kWh. The study projected the capacity DRIPE to be zero since the New England Independent System Operator designed its capacity auctions to avoid purchasing surpluses, and because new natural gas power plants are expected to set the capacity market price.

Source: Hornby, R. et al., 2015.

In order to assess DRIPE savings, analysts can estimate the potential market price change attributable to a particular energy efficiency or renewable energy resource based on a dispatch curve analysis as follows.

- **Step 1: Determine the time period of the planned operation for the energy efficiency or renewable energy resource.** Time periods may be defined by specific seasons or at certain times of the day.
- **Step 2: Determine the size of the resource (typically in MW) and the hourly shape if relevant.** (For more information, see "Step 1: Estimate the Energy Efficiency or Renewable Energy Operating Characteristics," in Section 3.2.4.)
- **Step 3: Develop a dispatch curve.** The dispatch curve can be based upon either generating unit data (i.e., capacity ratings and operating costs) or market clearing price data, typically available from the ISO or control area operator. See Section 3.4., "Tools and Resources," for data sources which provide generating unit data and market clearing price data. For more information, also see "Step 2: Identify the Marginal Units to Be Displaced," in Section 3.2.4. This method constructs a supply curve of all generating sources that can be dispatched and at what cost.

- **Step 4: Examine expected electricity demand and costs without the program.** Examine the BAU curve developed in Step 3 to determine the expected demand for electricity—and the costs—during the relevant time period.
- **Step 5: Consider the expected changes of the energy efficiency or renewable energy resource on electricity demand and prices.** Analyze a case with the energy efficiency or renewable energy resource by reducing demand or adding supply to represent the energy efficiency or renewable energy resource.
- **Step 6: Compare the wholesale market price results under both scenarios.** The difference is the wholesale market price reduction benefit (expressed in $/MWh or total dollars for the time period).

An illustration of this method is in the box on the next page, "Estimating Short-Run Wholesale Market Price Effects: An Illustration."

This method for calculating the market price change can be applied to the electric energy market and capacity market, if one exists in the region. This benefit can be calculated using spreadsheets, an economic dispatch model (e.g., GE MAPS, PROMOD IV), or an energy system model for a more aggregated estimate. Another method, used by the CPUC in California's avoided cost proceeding, is to use historical loads and prices (CPUC, 2006).

Increased Reliability and Power Quality

An expansion in the use of energy efficiency and some distributed renewable energy resources can improve both the reliability of the electricity system and power quality by helping to avoid power outages, maintaining proper grid voltage levels, and avoiding the need for redundant power supply. For example, California's investments in energy efficiency and demand response played a role in averting rolling blackouts in the summer of 2001. Power quality problems, in particular, occur when there are deviations in voltage level supplied to electrical equipment. Some forms of energy efficiency and renewable energy resources, such as fuel cells, can provide near perfect power quality to their hosts.

Reliability

Electric grid reliability relies upon the adequacy (i.e., having enough electricity supply to meet peak demand) and the performance (i.e., the ability to respond to disturbances) of the system. Energy efficiency can generate multiple benefits to electric grid reliability. Efficiency programs reduce long-term electricity growth and promote resource adequacy. Efficiency programs can defer the need to build new power plants to maintain grid operating reserve margins, defined as the grid's backup generating capacity and usually required to be in the range of 10 to 20 percent. Energy efficiency and distributed generation can also alleviate transmission constraints in regions where transmission capacity becomes congested. Finally, energy efficiency and renewable energy can help to avoid over-reliance on single sources of energy, or "lock-in." (SEEA, 2015). While measuring these benefits can be difficult, there are methods available that analysts can use.

Metrics for Assessing Adequacy of the System

Probabilistic reliability metrics commonly used to assess the adequacy of the system include loss of load expectation (LOLE), loss of load probability (LOLP), loss of load hours (LOLH), and expected unserved energy (EUE) (CPUC, 2015).

- *LOLE* is defined as the number of days per year when a shortage in generation capacity is expected to occur, and is expressed as an expected value (the industry standard is 0.1 days per year).
- *LOLP* is nearly identical to LOLE and shows the probability of a range of reserve margins being met. It is expressed as a probability, or a percentage of the year for which there is insufficient reserve margin.
- *LOLH* measures the total number of hours of generation capacity shortfalls over a time period (e.g., 8 hours per year), and does not specify how long a given outage occurred.

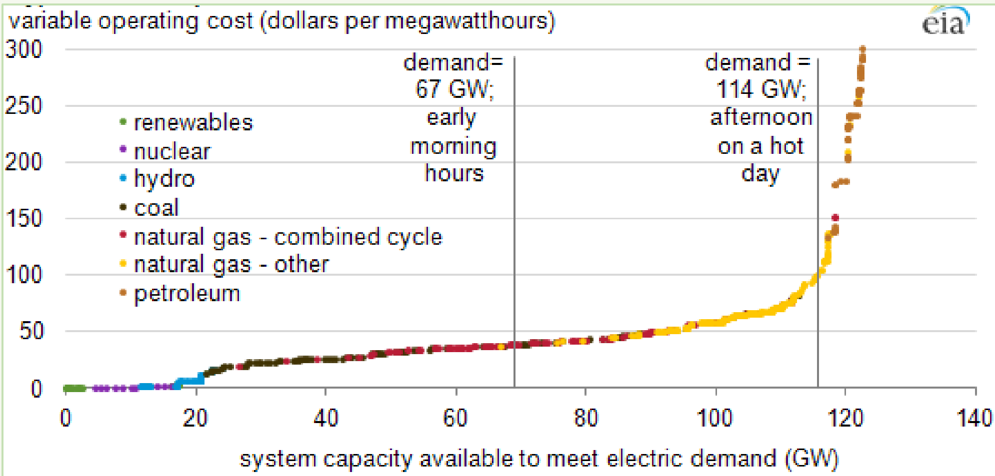
ESTIMATING SHORT-RUN WHOLESALE MARKET PRICE EFFECTS: AN ILLUSTRATION

To illustrate these steps with an example, assume a state decides to offer a rebate for residents who purchase ENERGY STAR certified air conditioners. Following the steps just outlined, the state can determine the potential effect of the rebate on wholesale electricity prices.

Step 1: The state determines that air conditioners in the region typically run on hot afternoons in the summer and so that is when the program would have the greatest impact.

Step 2: Based on the expected take-up rate of the rebate, the state calculates that the additional ENERGY STAR systems will lower demand by 4 GW.

Step 3: The state uses a curve constructed based on EIA-923 showing the variable operating costs for each dispatchable generator.



Source: EIA, 2012.

Step 4: Using the dispatch curve, the state finds that, in the absence of the rebate, the demand for electricity will be 114 GW, corresponding to a price of $100 per MWh.

Step 5: With the rebate program, the state expects demand to be reduced from 114 GW to 110 GW, which corresponds to a price of $75 per MWh in the dispatch curve.

Step 6: By lowering demand to 110 GW, the rebate program is expected to reduce wholesale prices by $25 per MWh (through a reduction in variable operating costs of the marginal generator, from $100 to $75) during hot summer afternoons.

The simplified equation for calculating savings from wholesale market price effects in this case is:

$$Savings\left(\frac{\$}{year}\right) = New\ Demand\ (in\ MW) * \#\ Hours\ of\ Demand\ Savings\ per\ Day * \#\ Days\ of\ Demand\ Savings\ per\ Year$$
$$* Reduction\ in\ Wholesale\ Prices\ from\ Displaced\ Marginal\ Generation\ \left(in\ \frac{\$}{MWh}\right) +$$
$$Demand\ Savings\ (in\ MW) * \#\ Hours\ of\ Demand\ Savings\ per\ Day$$
$$* \#\ Days\ of\ Demand\ Savings\ per\ Year\ * Wholesale\ Prices\ in\ Absence\ of\ Program\ \left(in\ \frac{\$}{MWh}\right)$$

If program savings of 4,000 MW (4 GW) were taking place over a 4-hour period each day for 90 summer days throughout the year, the program would save 110,000 MW * 4 hours per day * 90 days/year * $25/MWh + 4,000 MW * 4 hours per day * 90 days/year * $100/MWh = $1.044 billion each year in wholesale costs.

- *EUE* measures the amount of electricity shortfall during generation capacity shortages summed over a given time period, and also does not specify how long a given outage occurred. As a hypothetical example, the EUE for a 100-MW capacity shortage lasting one hour would equal 100 megawatt-hours (NERC, 2016).

As a general rule, the lower the LOLE, LOLP, LOLH, and EUE, the higher the reliability of the electricity system, and vice versa. See Section 3.4., "Tools and Resources," for potential resources on how to quantify reliability probabilistic metrics.

Metrics for Assessing Performance of the System

There are multiple indices to measure reliability from a performance perspective and they are relatively well established and straightforward to calculate. Some of the most common indices include:

- ***SAIFI (System Average Interruption Frequency Index):*** The average frequency of sustained interruptions per customer over a predefined area. It is calculated as the total number of customer interruptions divided by the total number of customers served.
- ***CAIDI (Customer Average Interruption Duration Index):*** The average time needed to restore service to the average customer per sustained interruption. It is calculated as the sum of customer interruption durations divided by the total number of customer interruptions.
- ***SAIDI (System Average Interruption Duration Index):*** Commonly referred to as customer minutes of interruption or customer hours, it provides information on the average time customers are interrupted. SAIDI = CAIDI * SAIFI, and represents the sum of the restoration time for each interruption event times the number of interrupted customers for each interruption event divided by the total number of customers.
- ***MAIFI (Momentary Average Interruption Frequency Index):*** Quantifies momentary interruptions resulting from each single operation of an interrupting device, such as a recloser. It is calculated as the total number of customer momentary interruptions divided by the total number of customers served.

Historical reliability data are often available. Converting reliability benefits into dollar values is complex, however, and the results of studies that have attempted to do so are controversial. For this reason, their use in support of resource decisions is less common than for other, well-established benefits, such as the avoided costs of generation, capacity, and T&D.[22]

Power Quality

Power quality refers to the consistency of voltage of electricity supplied to electrical equipment, usually meaning the voltage stays within plus or minus 5 percent. Maintaining consistent power quality is important; otherwise, electrical equipment can be damaged. Power quality improvements produce economic benefits for electricity consumers by avoiding damage to equipment and associated loss of business income and product, and, in some cases, the need for redundant power supply. For example, consumer and commercial electrical and electronic equipment is usually designed to tolerate extended operation at any line voltage within 5 percent nominal, but extended operation at voltages far outside that band can damage equipment or cause it to operate less efficiently. At the extreme, some commercial and industrial processes, such as silicon chip fabrication and online credit card processing, are so sensitive to outages or power quality deviations that customers take proactive steps to avoid these concerns, including construction of redundant transmission lines or installing diesel or battery backup power. The costs of such equipment could also be used to estimate the value of increased reliability and power quality.

The data needed to assess power quality benefits are neither consistently measured nor comprehensively collected and reported. Specialized monitoring equipment is typically necessary to measure power defects, and acceptable standards for power quality have been changing rapidly.

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[22] *The Interruption Cost Estimate Calculator (ICE) is a tool designed to estimate interruption costs (of events lasting longer than 16 hours) and benefits associated with reliability improvements (U.S. DOE, LBNL, and Nexant, 2015).*

Avoided Risks Associated with Long Lead-Time Investments such as the Risk of Overbuilding the Electricity System

Energy efficiency and renewable energy options provide increased flexibility to deal with uncertainty and risk related to large, conventional fossil fuel resources. For example, in terms of resource planning, if one is unsure that long-term forecasts for load growth are 100 percent accurate, then energy efficiency and renewable energy resources offer greater flexibility due to their modular nature and relatively quick installation times relative to conventional resources.[23]

All other things being equal, a resource or resource plan that offers more flexibility to respond to changing future conditions is more valuable than a less flexible resource or plan. Techniques such as decision-tree analysis or real option analysis provide a framework for assessing this flexibility. These methods involve distinguishing between events within one's control (i.e., decision nodes) and those outside of one's control (i.e., exogenous events) and developing a conceptual model for these events as they would occur over time. Specific probabilities are generally assigned to the exogenous events. The results of this type of analysis can include the identification of the best plan on an expected value basis (i.e., incorporating the uncertainties and risks) or the identification of lower risk plans.

Beyond the expected value of the plan, certain resources may have some "option value" if they allow (or do not prevent) other resource options in the future. For example, a plan that involves implementing some DSM in the short run can have value above its simple short-run avoided cost. If conditions are sufficient, the resource develops the capability for expanded DSM deployment in the future, if conditions call for it.

Reduced Risks From Deferring Investment in Conventional, Centralized Resources Pending Uncertainty in Future Environmental Regulations

Energy efficiency and renewable energy can reduce the cost of compliance with current and future air pollution control requirements. Utilities and states also see these resources as a way to reduce their financial risk from future regulations. In order to account for uncertainty and risk in decision-making processes, utilities and states can consider multiple scenarios of future regulations and prices. Comparing energy efficiency and renewable energy to larger scale power projects under these different scenarios can result in an understanding of the specific risks that large investments might have compared to more flexible renewable energy and energy efficiency resources. A scenario analysis can identify a cost premium to be added to least-cost, high-risk energy resources being considered for development, allowing for full information when making decisions.

When comparing new generation options in the face of stricter environmental regulations, some states and utilities are reducing financial risk by placing a higher cost premium on conventional resources relative to energy efficiency and renewable energy. For example, California's cap-and-trade program, which places a cost on each metric ton of carbon a

SCENARIO MODELING IN PACIFICORP'S 2013 INTEGRATED RESOURCE PLAN

Pacificorp's 2013 Integrated Resource Plan (IRP) considers 19 different future "core case" scenarios each with different assumptions including:

- Timing and level of CO_2 prices
- Natural gas and wholesale electricity prices
- Policy assumptions pertaining to federal tax incentives and RPS requirements
- Policy assumptions pertaining to coal unit compliance requirements driven by Regional Haze regulations
- Acquisition ramp rates for Class 2 DSM resource (from non-dispatchable, firm energy and capacity product offerings/programs) available and coal unit environmental investments
- By reviewing these scenarios, PacifiCorp is able to weigh options for the future of the utility systems under different potential regulations.

Source: PacifiCorp, 2013.

[23] *Nonetheless, energy efficiency and renewable energy resources carry their own risk of non-performance.*

utility emits, sends a price signal to utilities considering building new units. In February 2018, California auction settlement prices were $14.61 per metric ton of carbon dioxide equivalent (CARB, 2018).

Improved Fuel Diversity

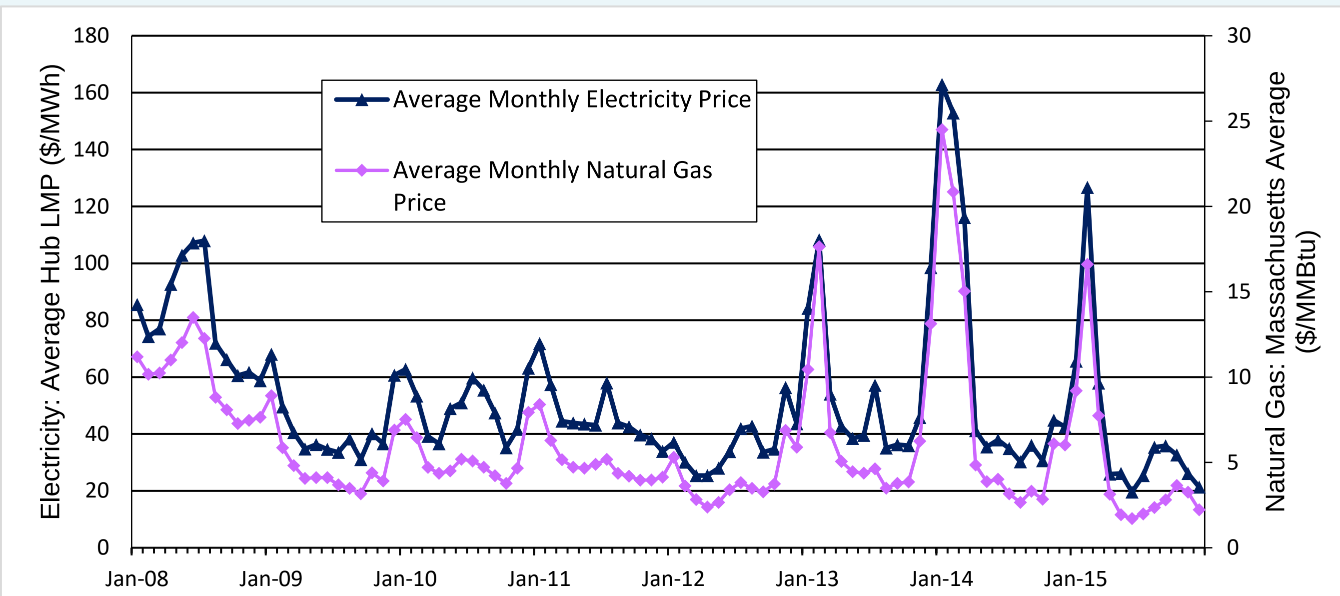
Portfolios that rely heavily on a few energy resources are highly affected by the unique risks associated with any single fuel source. In contrast, the costs of energy efficiency and renewable energy resources are not affected by fossil fuel prices and thus can hedge against fossil fuel price spikes by reducing exposure to this volatility.

Diversity in technology can also reduce the likelihood of supply interruptions and reliability problems. For example, while geothermal plants can be expensive to construct, they offer an almost constant supply of electricity and are best suited for baseload generation. Gas turbines, on the other hand, are relatively inexpensive to construct and can start quickly, but have a high operating cost and so are best suited for peaking generation. Figure 3-4 illustrates the relationship between electricity and natural gas prices in New England.

Two methods for estimating the benefits of fuel and technology diversification include market share indices and portfolio theory.

Figure 3-4: Natural Gas and Electricity Prices in New England

A large portion of New England's electricity is generated from natural gas. Due to this high dependence on one fuel source, and because fuel represents a large portion of the cost to produce electricity, natural gas and electricity prices are highly correlated.



Source: ISO New England, 2016.

Market Share Indices

- Market share indices, such as the Herfindahl-Hirschman Index and Shannon-Weiner Index, identify the level of diversity as a function of the market share of each resource.[24] Use of these indices is appropriate for preliminary resource diversity assessment and as a state or regional benchmark.

[24] *For more information about these indices, see U.S. Department of Justice and the Federal Trade Commission, Issued April 1992; Shannon, C. E. "A Mathematical Theory of Communication,"* Bell System Technical Journal *27: 379–423 and 623–656, July and October 1948. Market share indices are computationally simple, and the data required for the indices (annual state electricity generation by fuel type and producer type) are readily available from the EIA Form 923 database. Note that EIA Form 906 was superseded by EIA Form 923 starting in 2008. Both datasets are available at: https://www.eia.gov/electricity/data/eia923/index.html.*

- A limitation of these indices is that decisions on how to classify resources (e.g., calculating the share of all coal rather than bituminous and subbituminous coals separately) can have a large effect on the results. Another shortcoming is that the indices do not differentiate between resources that are correlated with each other (e.g., coal and natural gas) and thus can underestimate the portfolio risk when correlated resources are included.

Portfolio Theory

- The concept of portfolio theory suggests that portfolios of generation technologies should be assembled and evaluated based on the characteristics of the portfolio, rather than on a collection of individually assessed resources.
- Measures of the performance of a portfolio consider variance in load profile, whether the generator is dispatchable, and how quickly the generator can be dispatched. These measures account for risk and uncertainty by incorporating correlations between resources, as measured by the standard deviation of cost or some other measure of performance. The standard deviation can be calculated for a number of portfolios, each with a variety of different resources, to find portfolios that simultaneously minimize cost and risk. It is helpful to acknowledge this inherent trade-off between cost and risk; there is not a single portfolio that lowers both.

THE IMPORTANCE OF LOW PERFORMANCE CORRELATIONS

Similar resources (e.g., fossil fuels such as coal and oil) tend to face similar specific risks, and as a result their performances tend to be correlated. For example, coal and oil both emit CO_2 when burned and thus could be associated with future climate change regulatory risk, which in turn would likely increase costs and affect the performance of oil- or coal-fired generation. On the other hand, disparate resources (e.g., coal and wind) have lower performance correlations—and hence more value for offsetting resource-specific risks within the portfolio—than resources that have little disparity.

Improved Energy Security

While market share indices and portfolio analyses can estimate fuel and technology diversity, they do not readily incorporate the non-price and qualitative benefits of fuel diversity, such as energy independence, which can be a benefit of energy efficiency and renewable energy. Energy independence can improve energy security, for example when using domestic energy efficiency and renewable energy resources to reduce dependence on foreign fuel sources. Avoiding the use of imported petroleum may yield political and economic benefits by protecting consumers from supply shortages and price shocks. Energy and national security is also improved when the existence of one easily targeted large unit with onsite fuel is replaced with many smaller units that are located in a variety of locations. Care should be taken to consider price as well as factors that are not easily quantified when choosing among portfolios with different cost-risk profiles.

Summary of Secondary Electricity System Benefits

Table 3-11 outlines some of the factors that state decision makers can consider when deciding which secondary electricity system benefits to analyze, including available methods and examples, strengths, limitations, and purpose of analysis.

Table 3-11: Secondary Electricity System Benefits From Energy Efficiency and Renewable Energy Measures

Applicable Energy Efficiency and Renewable Energy Resources	Considerations for Determining Whether to Analyze	Who Usually Conducts or Commissions Analysis?	When Is Analysis Usually Conducted?
BENEFIT: Avoided ancillary services			
▪ Resources that can start during blackout, ramp up quickly, or provide reactive power ▪ Resources closer to loads	▪ Usually smaller benefits than traditionally analyzed benefits ▪ Market price data available for some services in some markets (e.g., PJM) ▪ Ancillary service savings from clean resources often site-specific and difficult to estimate ▪ Separating ancillary service value from capacity value in long-run analysis may be difficult	▪ Utilities conduct in-depth modeling ▪ State utility regulatory commissions and other stakeholders review utility's results and/or conduct own analysis	▪ Resource planning and released regulatory proceedings ▪ Area-specific DSM program development ▪ Policy studies
BENEFIT: Wholesale market price effects			
▪ All energy efficiency and renewable energy resources ▪ Resources that operate during peak hours	▪ Benefits depend on market/pricing structure and peaking resources and forecasted reserve margins ▪ Actual market price data generally available ▪ Studies to estimate benefits may be complex	▪ ISOs and utilities conduct in-depth modeling ▪ State utility regulatory commissions, other stakeholders review utility's results and/or conduct own analysis	▪ Resource planning and released regulatory proceedings ▪ Area-specific DSM program development ▪ Policy studies
BENEFIT: Increased reliability and power quality			
▪ Distributed renewable resources ▪ Energy efficiency and renewable energy resources close to load or with high power quality ▪ All resources that operate as baseload units ▪ All load-reducing energy efficiency resources that increase surplus generation and T&D capacity in region	▪ Historical reliability data often available ▪ Historical power quality data rare ▪ Studies for converting to dollar value complex and controversial ▪ Benefits especially valuable for manufacturing processes sensitive to power quality or regions where reliability is significant concern	▪ Utilities conduct in-depth modeling ▪ State utility regulatory commissions and other stakeholders review utility's results and/or conduct own analysis	▪ Usually ad hoc studies ▪ Policy studies

Applicable Energy Efficiency and Renewable Energy Resources	Considerations for Determining Whether to Analyze	Who Usually Conducts or Commissions Analysis?	When Is Analysis Usually Conducted?
BENEFIT: Avoided or reduced risks of overbuilding (associated with long lead-time investments, such as the risk of overbuilding the electricity system)			
▪ Distributed resources with short lead times ▪ Resources close to load ▪ All energy efficiency and renewable energy resources	▪ Historical load and load variability data often available ▪ Modeling varies from simple to complex	▪ Utilities conduct in-depth modeling ▪ State utility regulatory commissions and other stakeholders review utility's results and/or conduct own analysis ▪ Policy and risk management analysts conduct analysis	▪ Resource planning and released regulatory proceedings ▪ Policy studies
BENEFIT: Avoided or reduced risks of stranded costs (from deferring investment in conventional, centralized resources until environmental and climate change policies are implemented)			
▪ All energy efficiency and renewable energy resources	▪ Modeling varies from simple to complex ▪ Studies to estimate benefits may be complex ▪ Regulatory uncertainty adds to complexity of analysis	▪ Policy and risk management analysts conduct analysis	▪ Resource planning and released regulatory proceedings ▪ Policy studies
BENEFIT: Fuel and technology diversification			
▪ All energy efficiency and renewable energy resources	▪ Diversity metrics computable from generally available data ▪ Portfolio analysis of costs vs. risks adds complexity ▪ Ensuring inclusion of existing supply resources and incremental new resources	▪ State utility regulatory commissions conduct own analyses ▪ Utilities conduct in-depth modeling ▪ RTO/ISOs conduct own analyses	▪ State energy plans ▪ Resource planning and released regulatory proceedings ▪ Policy studies

3.3. CASE STUDIES

The following two case studies illustrate how assessing the electricity system benefits associated with energy efficiency and renewable energy can be used in the state energy planning and policy decision-making process. Information about a range of tools and resources analysts can use to quantify these benefits, including those used in the case studies, is available in Section 3.4., "Tools and Resources."

3.3.1. California Utilities' Energy Efficiency Programs

Benefits Assessed in Analysis

Electricity system benefits quantified in this case study include:

- Avoided electricity generation costs
- Avoided generation capacity costs
- Avoided ancillary services costs

- Avoided T&D capacity costs

Other benefits quantified in this case study include:

- Avoided environmental externality costs
- Avoided Renewable Portfolio Standard (RPS) costs

Energy Efficiency/Renewable Energy Program Description

In California, investor-owned utility (IOU) energy efficiency programs are funded by a small portion of electricity and gas rates included in customer bills, which provides over $1 billion per year. The programs span a variety of sectors encompassing residential homes and commercial buildings; large and small appliances; lighting and heating, ventilation, and air conditioning; industrial manufacturers; and agriculture. Within those sectors, IOUs take a number of approaches to efficiency programs, including:

- Financial incentives and rebates
- Research and development for energy efficiency technologies
- Financing mechanisms
- Codes and standards development
- Education, public outreach, and marketing

Four California IOUs, Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Southern California Gas Company, are the primary administrators of publicly funded energy efficiency programs. All of these programs are regulated by the CPUC to ensure they are meeting the goals and cost-effectiveness metrics set by the CPUC.

The primary benefits of demand-side resources, like energy efficiency, are the avoided costs related to generation and distribution of energy. In 2017, the CPUC approved an interim methodology developed by Energy and Environmental Economics, Inc. (E3) to calculate avoided costs, which is used to evaluate the cost-effectiveness of 2017–2040 utility energy efficiency programs in California. The updated methodology builds upon the previous avoided cost model that was used for estimating energy efficiency avoided costs since the 2011 cycle, and attempts to better reflect the expected future avoided costs for the California IOUs.

Methods Used

E3 conducted an analysis of IOU energy efficiency programs in 2017 to calculate the CPUC's avoided electricity generation costs, avoided generation capacity costs, avoided ancillary services costs, avoided T&D capacity costs, environmental externality costs, and avoided RPS costs. The analysts used the "Avoided Cost Calculator," an Excel-based spreadsheet model developed by E3 that incorporates CPUC-approved methods for use in demand-side cost-effectiveness proceedings. E3's methodology application for analyzing avoided costs is described in a detailed report issued in September 2017, *Energy Efficiency Avoided Costs 2017 Interim Update* (E3, 2017). The methodology accounts for six major cost benefits that are avoided when demand is reduced through installation of energy efficiency resources. To implement the methodology, E3 used the calculator to produce time- and location-specific cost estimates, and incorporate generation and T&D loss factors to reflect the fact that dispatched generation is greater than electricity delivered to customers due to electricity losses during transmission and distribution. It combines forecasts of the average value of each benefit with historical day-ahead and real-time energy prices, along with actual system loads reported by CAISO for 2015, to produce avoided costs with hourly granularity. Table 3-12 summarizes the methodology applied to each benefit to develop this level of granularity.

E3 used the calculator to develop location-specific results for the 16 California climate zones as defined by the Title 24 building standards to highlight the regional differences of electricity values in the state, which capture the effect of differences in climate on energy use.

Table 3-12: Summary of Methodology for Assessing Program Benefits

Benefit	Description	Basis of Annual Forecast	Basis of Hourly Shape
Avoided Electricity Generation Costs	The hourly wholesale value of avoided electricity	Forward market prices and the $/kWh fixed and variable operating costs of a combined-cycle gas turbine	Historical hourly day-ahead market price shapes from Market Redesign and Technology Upgrade (MRTU) Open Access Same-time Information System (OASIS)
Avoided Generation Capacity Costs	The avoided costs of building new generation capacity to meet system peak loads	Residual capacity value of a new simple-cycle combustion turbine	E3 Renewable Energy Capacity Planning (RECAP) model that generates outage probabilities by month/hour, and allocates the probabilities within each month/hour based on 2015 weather
Avoided Ancillary Services Costs	The avoided marginal costs of providing system operations and reserves for electricity grid reliability	Percentage of generation energy value	Directly linked with energy shape
Avoided T&D Capacity Costs	The avoided costs of expanding transmission and distribution capacity to meet peak loads	Marginal T&D costs from utility ratemaking filings	Hourly temperature data
Environmental Externality Costs	The cost of carbon dioxide emissions associated with the marginal generating resource	CO_2 cost forecast from the California Energy Commission's *2015 Integrated Energy Policy Report* mid-demand forecast, escalated at inflation beyond 2030	Directly linked with energy shape with bounds on the maximum and minimum hourly value
Avoided RPS Costs	The reduced purchases of renewable generation at above-market prices required to meet an RPS standard due to a reduction in retail loads	Cost of a marginal renewable resource less the energy market and capacity value associated with that resource	Flat across all hours

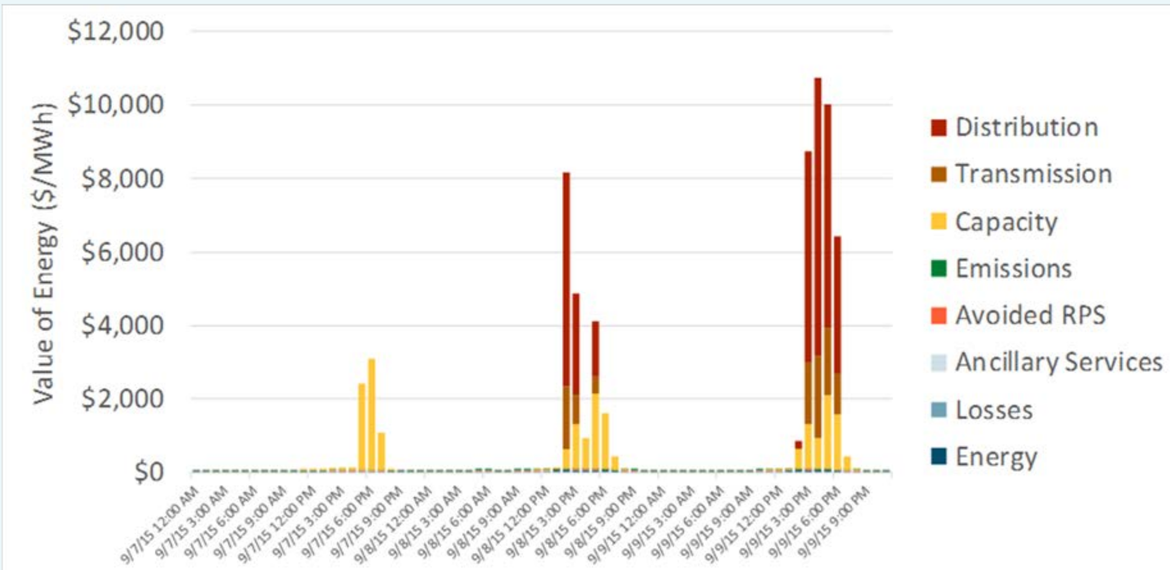
Source: E3, 2017.

Results

The results of E3's analysis demonstrate the value of estimating avoided costs in California using time- and location-specific data, which highlights the importance of reducing demand during peak hours. The study found that avoided costs (especially for distribution, but also for transmission and capacity) were particularly high during peak hours and the peak summer season.

Figure 3-5 breaks down avoided costs by type in PG&E's Sunnyvale territory over a three-day period. As shown, the marginal cost of energy is higher in the afternoons and evenings (peak hours) than in the morning. The highest peaks of total avoided cost shown in of over $10,000/MWh are driven primarily by avoided generation capacity *(yellow bars)* and avoided T&D capacity *(brown and red bars).* These types of avoided costs are concentrated during the peak hours of the day (the hours where electricity demand is highest and generation, transmission, and distribution capacity are most utilized) (E3, 2017).

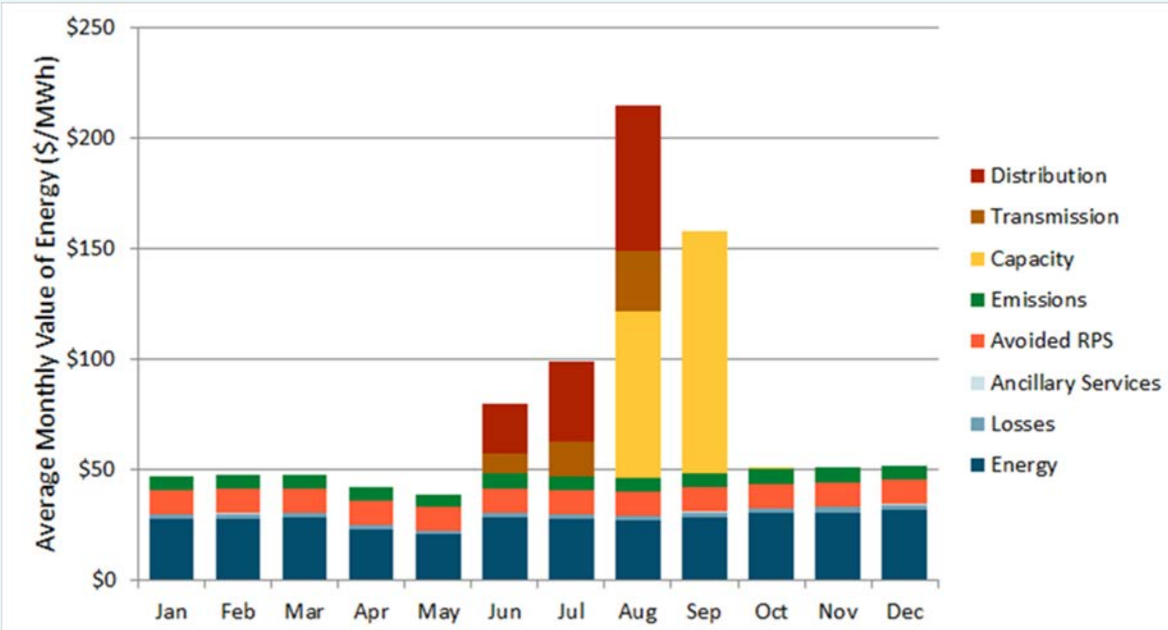
Figure 3-5: Three-Day Snapshot of Energy Values in Sunnyvale, CA (PG&E) in 2017



Source: E3, 2017.

Figure 3-6 demonstrates the value of electricity reductions in PG&E's Fresno territory by month. As shown, the average monthly value of energy is highest in the summer months when demand for electricity is highest and lower in other months. As a result, the value of generation capacity *(yellow bars)* and T&D capacity *(brown and red bars)* is concentrated in the summer months (E3, 2017).

Figure 3-6: Average Monthly Avoided Cost From Energy Efficiency in Fresno, CA (PG&E) in 2017



Source: E3, 2017.

Table 3-13 shows the costs and benefits to bill payers for each of California's four IOUs, as well as the whole state.[25] California's energy efficiency programs are estimated to have a total program lifetime benefit of $5.5 billion, 30 percent larger than the cost of the programs (CPUC, 2015).[26]

Table 3-13: Estimated Cost-Effectiveness Test Results for the California Investor-Owned Utilities' 2010–2012 Efficiency Programs ($Million)

Costs and Benefits	SDG&E	SoCalGas	SCE	PG&E	Total
Total costs to bill payers	$400	$379	$1,627	$1,825	$4,230
Total savings to bill payers	$404	$561	$2,329	$2,238	$5,532
Net benefits to bill payers	$4	$182	$702	$413	$1,302

Source: CPUC, 2015.

[25] *These estimates use a Total Resource Cost (TRC) test to assess cost-effectiveness. For more information, see http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Cost-effectiveness.htm*

[26] *As a result of the energy efficiency programs, California's investor-owned utilities project savings of about 7,745 GWh of electricity, 1,300 MW of peak summer demand, and 170,000 megatherms of natural gas from 2010 to 2012. Relative to a BAU baseline without the programs, the utilities expect to reduce carbon dioxide emissions by about 5,300,000 tons—the equivalent of the emissions of over one million cars over the same period.*

For More Information

Resource Name	Resource Description	URL Address
California Utilities' Energy Efficiency Programs Case Study		
Avoided Cost Calculator and *2017 Avoided Cost Interim Update*	This link leads to the Avoided Cost Calculator (updated in 217) as well as a detailed 2017 report that describes the methods used to calculate avoided costs for energy efficiency cost-effectiveness valuation for 2017–2040.	http://www.cpuc.ca.gov/General.aspx?id=5267
Energy Efficiency 2010–2012 Evaluation Report	This 2015 CPUC report describes the results of consumer-funded energy efficiency programs.	http://www.cpuc.ca.gov/General.aspx?id=6391

3.3.2. Energy Efficiency and Distributed Generation in Massachusetts

Benefits Assessed in Analysis

Electricity system benefits quantified in this case study include:

- Reduction in wholesale market clearing prices
- Reduction in avoided costs of electricity generation/wholesale electricity purchases
- Reduction in T&D costs
- Reduction in ancillary service costs
- Reduction in long-run avoided costs of power plant capacity

Other benefits quantified in this case study include:

- Increased economic activity
- Job creation
- Avoided greenhouse gas (CO_2) emissions

Energy Efficiency/Renewable Energy Program Description

The Green Communities Act (GCA), passed by the Massachusetts legislature in July 2008, created energy efficiency and renewable energy policies focused on increasing:

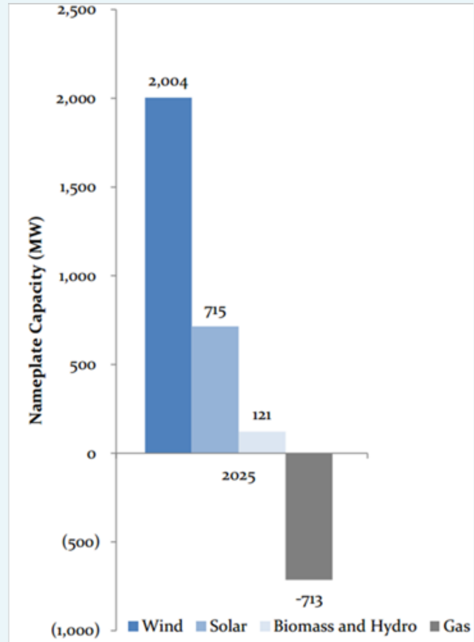
- Utility energy efficiency programs
- Solar deployment through net metering
- Grid-scale renewable energy development
- Massachusetts's Renewable Portfolio Standard (RPS) targets
- Funding for local energy efficiency and renewable energy projects

In 2014, Analysis Group released an evaluation of the economic and emissions impact of the GCA from 2010 through 2015 (see Figure 3-7).

Methods Used

The analysis compared the observed program impacts to a counterfactual scenario using modeled assumptions in which the GCA policies were not implemented. This comparison allowed Analysis Group to attribute costs and benefits properly to the GCA. The modeling only examined the impacts of energy efficiency and renewable energy projects implemented during the first 6 years of the GCA, from 2010 to 2015, but projected savings for these projects through 2025. The modeling assumes that energy efficiency savings expire after the end of their useful life (10 years) and that increased renewable generation resulting from the GCA generates energy through 2025.

Figure 3-7: Capacity Additions in New England Due to GCA in 2025



Source: "The Impacts of the Green Communities Act on the Massachusetts Economy: A Review of the First Six Years of the Act's Implementation" (Analysis Group, March 4, 2014).

The analysis used the PROMOD IV model to determine electricity system effects through 2025 resulting from lower consumer demand and increased renewable energy supply. The analysis also used the IMPLAN model to examine the net macroeconomic effects from increased costs due to energy efficiency programs and lost revenue from fossil fuel generators, as well as benefits from reduced consumer energy bills (lower avoided costs of electricity generation/wholesale electricity purchases, T&D costs, and ancillary service costs), lower power demand (lower long-run avoided costs of power plant capacity), construction and installation of energy efficiency and renewable energy measures, and increased renewable energy revenue. The analysis converts these impacts into inputs (in dollar terms) which are modeled in IMPLAN producing impacts on key output variables such as employment, income, and economic value-added. The impact of the GCA on these key output variables was calculated from the difference between two IMPLAN model runs: the counterfactual, non-GCA scenario and the observed GCA impact scenario.

Results

The analysis (see Table 3-14) shows that the GCA is projected to result in the following impacts by 2025:

- Addition of 2,800 MW of renewable capacity (over 2,000 MW of wind, 700 MW of solar)
- Over 700 MW of reduced natural gas capacity
- Over 10 Terawatt-hours (TWh) of reduced electricity generation
- Net economic benefit of over $1 billion ($600 million) at a 3 percent (7 percent) discount rate
- Nearly 16,400 jobs created

Table 3-14: Net Economic Impact of GCA by 2025

Scenario	3% Discount Rate		7% Discount Rate	
	Value Added ($bn)	Jobs	Value Added ($bn)	Jobs
Base	$1.2	16,395	$0.6	16,395
High Gas	$1.8	21,651	$1.1	21,651
Low Gas	$0.6	11,187	$0.2	11,187

Source: "The Impacts of the Green Communities Act on the Massachusetts Economy: A Review of the First Six Years of the Act's Implementation," (Analysis Group, March 4, 2014).

Policies created through the GCA reduce wholesale energy costs paid by Massachusetts customers through increased energy efficiency and distributed generation deployment. The study estimates, due to energy efficiency and renewable energy actions already completed, that the GCA is expected to reduce annual wholesale electricity prices by $2.51 per MWh in 2020, declining slightly to $1.47 per MWh in 2025.

The study also finds, due to energy efficiency and renewable energy actions already completed, that the GCA is expected to reduce annual greenhouse gas emissions by more than 2 million metric tons (MMT) CO_2 per year through 2025, when cumulative reductions exceed 30 MMT CO_2.

For More Information

Resource Name	Resource Description	URL Address
Energy Efficiency and Distributed Generation in Massachusetts Case Study		
The Impacts of the Green Communities Act on the Massachusetts Economy: A Review of the First Six Years of the Act's Implementation	This 2014 report by the Analysis Group describes economic impacts of the Massachusetts Green Communities Act.	http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/analysis_group_gca_study.pdf

3.4. TOOLS AND RESOURCES

A number of available data sources, tools, and general resources are available for analysts to implement the methods described in this chapter. This section lists these resources and where you can obtain them, organized by estimation type and method.

Please note: While this Guide *presents the most widely used methods and tools available to states for assessing the multiple benefits of policies, it is not exhaustive. The inclusion of a proprietary tool in this document does not imply endorsement by EPA*.

3.4.1. Tools and Resources for Quantifying Primary Electricity System Benefits

Analysts can use a range of available data sources, tools, and resources to estimate the primary electricity system benefits of energy efficiency and renewable energy initiatives.

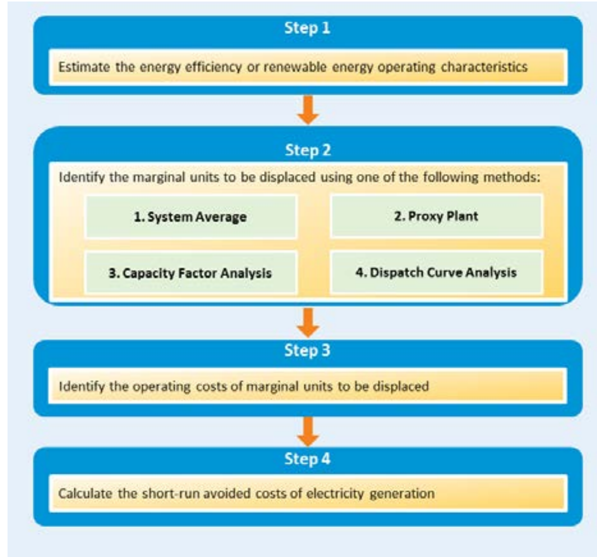
Tools and Resources for Estimating Avoided Costs of Electricity Generation or Wholesale Electricity Purchases

Resources detailed below serve as applicable data sources and tools for estimating avoided costs of electricity generation or wholesale electricity purchases.

Data Sources

Data Sources for Energy Efficiency and Renewable Energy Resource Operating Characteristics

In order to estimate avoided costs of electricity generation or wholesale electricity purchases, it is necessary to identify the operating costs of the marginal units to be displaced. Analysts can use the range of data sources listed below to identify the operating characteristics of the relevant energy efficiency and renewable energy resources. In addition to these data sources, load impact profile data for energy efficiency measures may be available for purchase from various vendors, but typically are not publicly available in any comprehensive manner.



- **3Tier**. This resource provides customized data and services that NREL sources for its Eastern and Western Wind Datasets. https://www.3tier.com
- **American Wind Energy Association**. This resource provides wind profiles. www.awea.org
- **AWS Truepower**. This resource provides customized data and services related to wind profiles for purchase. https://www.awstruepower.com/
- **California Database for Energy Efficient Resources (DEER).** DEER provides estimates of energy and peak demand savings values, measure costs, and effective useful life of efficiency measures. http://www.deeresources.com/
- **DOE's NEMS Model.** This resource provides wind profiles. https://www.eia.gov/outlooks/aeo/info_nems_archive.php
- **Homer's Energy Model**. This model can convert solar irradiation data to units of solar power. http://www.homerenergy.com/
- **New York State Energy Research and Development Authority's (NYSERDA) report, *Energy Efficiency and Renewable Energy Resource Development Potential in New York State, 2014***. This report on energy efficiency and renewable energy potential provides technology production profiles. Other states or regions may have similar reports. http://www.nyserda.ny.gov/-/media/Files/EDPPP/Energy-Prices/Energy-Statistics/14-19-EE-RE-Potential-Study-Vol1.pdf
- **Northeast Energy Efficiency Partnership's Regional Energy Efficiency Database (REED).** REED contains data on annual energy savings, peak demand savings, avoided air emissions, program expenditures, job creation impacts, cost of saved energy, program funding sources, and supporting information. http://www.neep.org/initiatives/emv-forum/regional-energy-efficiency-database
- **NREL's Eastern and Western Wind Datasets.** These datasets provide wind profiles. https://www.nrel.gov/grid/eastern-western-wind-data.html
- **NREL's Energy Analysis Site**. This site hosts Homer's Energy model and NREL's System Advisor Model. https://www.nrel.gov/analysis/
- **NREL's National Solar Radiation Database.** This database has a solar irradiation dataset with data in time intervals as small as half an hour. http://rredc.nrel.gov/solar/old_data/nsrdb/

- **NREL's System Advisor Model (SAM).** This model can convert solar irradiation data to units of solar power. https://sam.nrel.gov
- **NREL's Wind Prospector Tool.** This tool provides wind profiles. https://maps.nrel.gov/wind-prospector/
- **PV Watts**. This resource can convert solar irradiation data to units of solar power. http://pvwatts.nrel.gov/
- **Technical Resource Manuals (TRMs).** TRMs are documents used in 21 states to help estimate the impact of energy efficiency programs and can include hourly load profiles that display energy usage for different technologies throughout each hour of the day. For example, TRMs can be used to quantify the impact of light-emitting diode lighting installations on residential energy consumption, and contain generally applicable assumptions such as the number of hours in operation of different lighting technologies. TRMs are usually developed by public utility commissions (such as those in New York, Pennsylvania, and Vermont), as well as non-profit stakeholder groups (such as the Northeast Energy Efficiency Partnership). http://energy.gov/sites/prod/files/2013/11/f5/emvscoping_databasefeasibility_appendices.pdf

Data Sources for Dispatch Curve Analysis

Dispatch curve analyses examine historical hourly dispatch data to estimate the characteristics and frequency of each generating unit on the margin. Constructing a dispatch curve requires data on historical utilization of generating units; operating costs and emissions rates (if emissions are included in the analysis) for the most disaggregate time frame available; hourly regional loads; and electricity transfers between the control areas of the region and outside the region of interest. Sources for these required data are described below.

- **ABB's Velocity Suite**. Velocity Suite provides information on market participants and industry dynamics across commodities. http://new.abb.com/enterprise-software/energy-portfolio-management/market-intelligence-services/velocity-suite
- **EIA's Annual Energy Outlook.** This resource provides long-term electricity and fuel price projections. http://www.eia.doe.gov/oiaf/aeo/index.html
- **EIA's Electricity Data**. Operating cost and historical utilization data can typically be obtained from the EIA or the local load balancing authority. Often these sources can also provide generator-specific emissions rates for estimating potential emissions reductions from energy efficiency and renewable energy. http://www.eia.gov/electricity/
- **EIA's Form EIA-860.** This form provides generator-level information about existing and planned generators and associated environmental equipment at electric power plants with 1 MW or greater of combined nameplate capacity. https://www.eia.gov/electricity/data/eia860/
- **EIA's Form EIA-861**. This form provides information such as peak load, generation, electric purchases, sales, revenues, customer counts and DSM programs, green pricing and net metering programs, and distributed generation capacity. https://www.eia.gov/electricity/data/eia861/
- **EIA's Form EIA-923**. This form contains generator and fuel cost data by plant and can be used as an indicator for operating costs. https://www.eia.gov/electricity/data/eia923/
- **EPA's Air Market Program Data (AMPD).** AMPD is a web-based application that allows users easy access to both current and historical data collected as part of EPA's emissions trading programs. https://ampd.epa.gov/ampd/
- **EPA's eGRID Database.** This database provides historic data on or estimates of, capacity factors for individual plants which can be used in displacement curve analysis. https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid

- **FERC Form 1.** FERC Form 1 is the form filed annually by major electric utilities. This comprehensive financial and operating report can be used as a source of data for dispatch curve analysis. https://www.ferc.gov/docs-filing/forms/form-1/viewer-instruct.asp
- **FERC Form 423.** This form is a compilation of data for cost and quantity of fuels delivered to electric power plants. https://www.ferc.gov/docs-filing/forms.asp#423
- **FERC Form 714 (control area information).** This form can provide data on control area hourly marginal costs. http://www.ferc.gov/docs-filing/forms/form-714/data.asp
- **ISO New England**. ISO New England provides market clearing price data for northeastern states that can be used to develop a dispatch curve. https://www.iso-ne.com/markets-operations/markets/forward-capacity-market
- **Platts' MegaWatt Daily.** Platts publishes forward electricity market prices through this paid subscription newsletter. http://www.platts.com/products/megawatt-daily

Tools

Sophisticated Tools for Estimating Short-Run Avoided Costs: Economic Dispatch Models

Economic dispatch models determine the optimal output of electricity systems over a given timeframe (1 week, 1 month, 1 year, etc.) for a given time resolution (sub-hourly to hourly). These models generally include a high level of detail on the unit commitment and economic dispatch of electricity systems, as well as on their physical operating limitations. There are several economic dispatch models available for decision makers to use:

- **GE Multi-Area Production Simulation (GE MAPS™).** GE MAPS, developed and supported by GE Energy and supported by other contractors, is a tool designed to model the interaction between generation and transmission systems, allowing users to assess the value of a portfolio of generating units and identify transmission bottlenecks constraining the electric grid. A chronological model that contains detailed representation of generation and transmission systems, GE MAPS can also be used to study the impact on total system emissions that result from the addition of new generation. GE MAPS software integrates highly detailed representations of a system's load, generation, and transmission into a single simulation. This enables calculation of hourly production costs in light of the constraints imposed by the transmission system on the economic dispatch of generation. http://www.geenergyconsulting.com/practice-area/software-products/maps
- **Integrated Planning Model (IPM)®.** IPM, developed and supported by ICF, simultaneously models electric power, fuel, and environmental markets associated with electric production. It is a capacity expansion and economic dispatch model. Dispatch is based on seasonal, segmented load duration curves, as defined by the user. IPM also has the capability to model environmental market mechanisms such as emissions caps, trading, and banking. System dispatch and boiler and fuel-specific emission factors determine projected emissions. IPM can be used to model the impacts of energy efficiency and renewable energy resources on the electric sector in the short and long term. http://www.icf.com/resources/solutions-and-apps/ipm
- **Market Analytics – Zonal Analysis, Powered by PROSYM.** PROSYM, owned by ABB, allows users to forecast market prices from periods ranging from 1 week to 40 years into the future and analyze the effects of fuel prices, plant outages, load uncertainty, hydro availability, and emissions on market prices. A chronological electric power production costing simulation computer software package, PROSYM is designed for performing planning and operational studies. As a result of its chronological nature, PROSYM accommodates detailed hour-by-hour investigation of the operations of electric utilities. Inputs into the model are fuel costs, variable O&M costs, and startup costs. Output is available by regions, by plants, and by plant types. The model includes a

pollution emissions subroutine that estimates emissions with each scenario. http://new.abb.com/enterprise-software/energy-portfolio-management/market-analysis/zonal-analysis

- **PLEXOS for Power Systems™.** PLEXOS, owned by Energy Exemplar, uses mathematical optimization techniques to create a simulation system for the electric power sector, allowing users to minimize future investment costs with respect to capacity expansion planning, examine scenarios involving expansion of renewable energy technologies, and model ancillary services. A simulation tool that uses LP/MIP (Linear Programming/Mixed Integer Programming) optimization technology to analyze the power market, PLEXOS contains production cost and emissions modeling, transmission modeling, pricing modeling, and competitiveness modeling. The tool can be used to evaluate a single plant or the entire power system. http://www.energyexemplar.com

- **PROMOD IV.** PROMOD IV, owned by ABB, is used for locational marginal price (LMP) forecasting, financial transmission right valuation, environmental analysis, asset valuations (generation and transmission), transmission congestion analysis, and purchased power agreement evaluations. A detailed generator and portfolio modeling system, PROMOD IV can incorporate details in generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operation conditions, and market system operations. http://new.abb.com/enterprise-software/energy-portfolio-management/market-analysis/promod-iv

Tools and Resources for Estimating Long-Run Avoided Costs of Power Plant Capacity

The avoided cost of building and operating new power plants are the avoided costs of power plant capacity that can be estimated using either basic estimation or sophisticated simulation methods. Data sources and relevant tools to assist with this process are described below.

Data Sources

Utilities are one possible source of data for estimating long-run avoided costs of power plant capacity and often provide this information to public utility commissions in resource planning and plant acquisition proceedings. Other data sources include:

- **EPA's Power Sector Modeling using the Integrated Planning Model (IPM).** This resource provides information and documentation on EPA's application of IPM to analyze the impact of air emissions policies on the U.S. electric power sector. https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling

- **FERC Form 1**. This form can provide information for dispatch curve analyses. http://www.ferc.gov/docs-filing/forms/form-1/viewer-instruct.asp and http://www.ferc.gov/docs-filing/elibrary.asp

- **Regional Reliability Organizations***.* Organizations such as NERC can provide information on required reserve margins. http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

- **Regional Transmission Organizations, Independent System Operators, and Power pools***.* These sources maintain supply and demand projections by region and often sub-region.

- **SEC 10-Q Filings.** These quarterly filings provide company information on historical financial data and are available from the SEC EDGAR system. http://www.sec.gov/edgar.shtml

- **Securities and Economic Exchange Commission (SEC) 10K Filings.** These annual filings provide individual utility historical financial data. http://www.sec.gov/edgar/searchedgar/ companysearch.html

Tools

Electric Sector-Only Capacity Expansion Models

Capacity expansion models determine the optimal generation capacity and/or transmission network expansion in order to meet an expected future demand level and comply with a set of national, regional, or state specifications. Commonly used electric sector-only capacity expansion models for calculating long-run avoided costs of power plant capacity include:

- **AURORA**. The AURORA model, developed by EPIS LLC, provides electric market price forecasting, estimates of resource and contract valuation and net power costs, long-term capacity expansion modeling, and risk analysis of the energy market. http://epis.com/aurora/
- **EGEAS**. The Electric Generation Expansion Analysis System (EGEAS), developed by the Electric Power Research Institute, is a set of computer modules that are used to determine an optimum expansion plan or simulate production costs for a pre-specified plan. Optimum expansion plans are based on annual costs, operating expenses, and carrying charges on investment. http://eea.epri.com/models.html#tab=3
- **e7 Capacity Expansion.** e7 Capacity Expansion, developed by ABB, is an energy portfolio management solution covering resource planning, capacity expansion, and emissions compliance. It enables resource planners and portfolio managers to assess and develop strategies to address current and evolving RPSs and emissions regulations. http://new.abb.com/enterprise-software/energy-portfolio-management/commercial-energy-operations/system-optimizer-strategist
- **e7 Portfolio Optimization**. Portfolio Optimization models unit operating constraints and market conditions to facilitate the analysis and simulation of scenarios. The model optimizes a combined portfolio of supply resources and energy efficiency or distributed generation assets modeled as virtual power plants. http://new.abb.com/enterprise-software/energy-portfolio-management/commercial-energy-operations/portfolio-optimization
- **Integrated Planning Model (IPM)®.** IPM, developed by ICF, simultaneously models electric power, fuel, and environmental markets associated with electric production. It is a capacity expansion and economic dispatch model. IPM also has the capability to model environmental market mechanisms such as emissions caps, trading, and banking. System dispatch and boiler and fuel-specific emission factors determine projected emissions. IPM can be used to model the impacts of energy efficiency and renewable energy resources on the electric sector in the short and long term. http://www.icf.com/resources/solutions-and-apps/ipm
- **Long-Range Energy Alternatives Planning System (LEAP).** LEAP is an integrated, scenario-based modeling tool developed by the Stockholm Environment Institute. LEAP can be used to track energy consumption, production, and resource extraction in all sectors of the economy at the city, regional, state, or national scale. Beginning in 2018, LEAP includes the integrated benefits calculator, which can be used to estimate health (mortality), agriculture (crop loss) and climate (temperature change) impacts of scenarios. It can be used to account for both energy sector and non-energy sector greenhouse gas emissions sources and sinks, and to analyze emissions of local and regional air pollutants, and short-lived climate pollutants. www.energycommunity.org
- **NREL's Regional Energy Deployment System (ReEDS).** ReEDS, developed by NREL, is a long-term capacity expansion model that determines the potential expansion of electricity generation, storage, and transmission systems throughout the contiguous United States over the next several decades. ReEDS is designed to determine the cost-optimal mix of generating technologies, including both conventional and renewable energy, under power demand requirements, grid reliability, technology, and policy constraints. Model outputs are

generating capacity, generation, storage capacity expansion, transmission capacity expansion, electric sector costs, electricity prices, fuel prices, and carbon dioxide emissions. http://www.nrel.gov/analysis/reeds/

- **NREL's Resource Planning Model (RPM).** RPM is a capacity expansion model designed to examine how increased renewable deployment might impact regional planning decisions for clean energy or carbon mitigation analysis. RPM includes an optimization model that finds the least-cost investment and dispatch solution over a 20-year planning horizon for different combinations of conventional, renewable, storage, and transmission technologies. The model is currently only available for regions within the Western Interconnection, while a version for regions in the Eastern Interconnection is under development. https://www.nrel.gov/analysis/models-rpm.html

Whole Energy–Economy System Planning Models

Energy system-wide models with electricity sector capacity expansion capability include:

- **DOE's National Energy Modeling System (NEMS).** NEMS is a system-wide energy model (including demand-side sectors) that represents the behavior of energy markets and their interactions with the U.S. economy. The model achieves a supply/demand balance in the end-use demand regions, defined as the nine Census divisions, by solving for the prices of each energy product that will balance the quantities producers are willing to supply with the quantities consumers wish to consume. The system reflects market economics, industry structure, and existing energy policies and regulations that influence market behavior. The Electric Market Model, a module within NEMS, forecasts the actions of the electric power sector over a 25-year time frame and is an optimization framework. NEMS is used to produce the EIA's AEO, which projects the long-term future U.S. energy system and is used as a benchmark against which other energy models are assessed. https://www.eia.gov/outlooks/aeo/info_nems_archive.php
- **Energy 2020.** Energy 2020, developed by Systematic Solutions, is a simulation model that includes all fuel, demand, and supply sectors and simulates energy consumers and suppliers. This model can be used to capture the economic, energy, and environmental impacts of national, regional, or state policies. Energy 2020 models the impacts of an energy efficiency or renewable energy measure on the entire energy system. User inputs include new technologies and economic activities such as tax breaks, rebates, and subsidies. Energy 2020 uses emissions rates for NO_X, CO_2, SO_2, and particulate matter for nine plant types included in the model. It is available at the national, regional, and state levels. http://www.energy2020.com/
- **MARKet Allocation (MARKAL) Model.** MARKAL was originally developed by the U.S. DOE Brookhaven National Laboratory. Now, the model and its successor, *TIMES (The Integrated MARKAL-EFOM System)*, are developed and supported through the Energy Technology Systems Analysis Program of the International Energy Agency. These models are very similar, but TIMES includes functionality improvements and enhancements. Both MARKAL and TIMES determine the least-cost pattern of technology investment and utilization required to meet specified end-use energy demands (e.g., lumens for lighting, watts for heating, and vehicle miles traveled for transportation), while tracking the resulting criteria pollutant and greenhouse gas emissions. By adding constraints or changing various assumptions, these models can be applied to examine how those changes affect the optimal evolution of the energy system. For example, the requirement that greenhouse gases be reduced by 80 percent by 2050 could be added, and the models would determine the least-cost technological and fuel pathway for meeting this target. Similarly, a representation of an end-use energy efficiency requirement could be added, and the models used to evaluate its long-term system-wide impacts. MARKAL and TIMES have been applied by various groups in the United States and around the world for national, regional, and even metropolitan-scale applications. A dataset must be developed to represent current and future energy supplies, demands, and technologies for each application. For example, EPA has developed a U.S. Census-division level

MARKAL database that is available upon request (Lenox et al. 2013). http://iea-etsap.org/index.php/etsap-tools/model-generators/markal and http://iea-etsap.org/index.php/etsap-tools/model-generators/times

Other Tools for Estimating the Long-Run Avoided Costs of Power Plant Capacity

- **NREL's Jobs and Economic Development Impact (JEDI) model.** This free tool is designed to allow users to estimate the economic cost and impacts of constructing and operating power generation assets. The tool provides plant construction costs, as well as fixed and variable operating costs. http://www.nrel.gov/analysis/jedi/

Tools and Resources for Estimating Avoided Electricity Losses During Transmission and Distribution

Data Sources

- **EIA's Annual Energy Outlook (AEO).** Avoided U.S. T&D loss percentages for use in energy efficiency and distributed energy programs can be determined as *((Net Generation to the Grid + Net Imports – Total Electricity Sales)/Total Electricity Sales)*. This percentage considers all T&D losses that occur between net generation and electricity sales. The data for a particular year are available from the AEO, Table A8, available at: http://www.eia.gov/forecasts/aeo/

Resources

- **DOE's *Impacts of Demand-Side Resources on Electric Transmission Planning*.** This report assesses the relationship between high levels of demand-side resources (including end-use efficiency, demand response, and distributed generation) and investment in new transmission or utilization of existing transmission. http://energy.gov/epsa/downloads/report-impacts-demand-side-resources-electric-transmission-planning

Tools and Resources for Estimating Avoided Transmission and Distribution Capacity Costs

The follow resources support methods for estimating avoided T&D capacity costs:

Resources

- **DOE's *Impacts of Demand-Side Resources on Electric Transmission Planning*.** This report assesses the relationship between high levels of demand-side resources (including end-use efficiency, demand response, and distributed generation) and investment in new transmission or utilization of existing transmission. http://energy.gov/epsa/downloads/report-impacts-demand-side-resources-electric-transmission-planning

- **NYSERDA's *Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure*:** This report provides an overview of avoided T&D costs that analysts can assess as well as case studies that highlight programs that have quantified avoided T&D costs. https://www.nyserda.ny.gov/-/media/Files/Publications/Research/Electic-Power-Delivery/Deployment-of-Distributed-Generation-for-Grid-Support.pdf

Tools

Specialized proprietary models of the T&D system's operation may be used to identify the location and timing of system stresses. Examples of such models include the following:

- **GridLAB-D.** Developed by the U.S. Department of Energy's Pacific Northwest National Laboratory, this is a power distribution system simulation and analysis tool to assist utilities in analyzing the impact of new end-use energy technologies, distributed energy resources, distribution automation, and retail markets on the electric distribution system. http://www.gridlabd.org/

- **OpenDSS.** Designed to simulate electric utility power distribution systems, this tool supports analyses of future increases in smart grid, grid modernization, and renewable energy technology. http://smartgrid.epri.com/SimulationTool.aspx
- **Power Transmission System Planning Software (PSS®E).** PSSE offers probabilistic analyses and dynamics modeling capabilities for transmission planning and operations. http://w3.siemens.com/smartgrid/global/en/products-systems-solutions/software-solutions/planning-data-management-software/planning-simulation/pages/pss-e.aspx
- **PowerWorld Simulator.** PowerWorld Corporation offers an interactive power systems simulation package designed to simulate high-voltage power systems operation on a variable time frame. https://www.powerworld.com/products/simulator/overview

General Resources for Quantifying Primary Electricity System Benefits

In addition to the data sources, tools, and other resources described above, analysts can refer to the following general resources to estimate primary electricity system benefits.

- **DOE's Grid Modernization Multi-Year Program Plan***.* The value of distributed energy resources, such as solar PV, community wind, energy storage, electric vehicles, microgrids, and demand response varies across both location and time. The Grid Modernization Initiative is developing an analytical framework and tools to help state decision makers value benefits, costs, and impacts of DER, including the changing impact of DER over time as more energy efficiency and distributed generation resources are added to the grid. https://energy.gov/sites/prod/files/2016/01/f28/Grid%20Modernization%20Multi-Year%20Program%20Plan.pdf
- **DOE's Grid Project Impact Quantification (Grid Project IQ) Screening Tool**. The Grid Project IQ screening tool provides insight into smart grid-related technology deployments. It helps users quickly explore the outcomes of adding a new project to an existing power system from a web browser. With Grid Project IQ, users can quantify changes in total energy, peak power, greenhouse gas and criteria air pollutant emissions, ramping rates, and generation fossil fuel costs. https://www.energy.gov/oe/activities/technology-development/grid-modernization-and-smart-grid/grid-project-impact
- ***Evolution of Wholesale Electricity Market Design with Increasing Levels of Renewable Generation*****.** This 2014 NREL report focuses on characteristics of variable generation and its relevance to wholesale electricity market designs. https://www.nrel.gov/docs/fy14osti/61765.pdf
- ***Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System****.* NREL's 2014 report provides information on methods for analyzing the benefits and costs of distributed photovoltaic generation. https://www.nrel.gov/docs/fy14osti/62447.pdf

3.4.2. Tools and Resources for Quantifying Secondary Electricity System Benefits

Analysts can use a range of available resources and tools to estimate secondary electricity system benefits.

Data Sources

The following data sources provide relevant information for quantifying secondary electricity system benefits.

- **EIA's Form EIA-906/920 (power plant database)**, **now EIA-923***.* This database provides data on annual state electricity generation by fuel type and producer type that can be used in market share indices. This source is relevant for estimating improved fuel diversity benefits. http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html

- **ISO New England**. ISO New England provides market clearing price data for northeastern states that can be used to develop a dispatch curve. This source is relevant for estimating benefits from reduction in wholesale market clearing prices. https://www.iso-ne.com/markets-operations/markets/forward-capacity-market
- **NY ISO Ancillary Services Prices.** NY ISO publishes ancillary service prices for voltage regulation in $/MWh on an hourly basis for the state of New York. This source is relevant for estimating benefits from avoided ancillary services costs. http://www.nyiso.com/public/markets_operations/market_data/pricing_data/index.jsp

Resources

The following report scan be used to inform the quantification of reliability benefits.

- ***Probabilistic Assessment Technical Guideline Document.*** This report, put out by the North American Electric Reliability Corporation (NERC), details methodologies to probabilistically estimate reliability metrics. https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf
- ***State Approaches to Demand Reduction Induced Price Effects: Examining How Energy Efficiency Can Lower Prices for All***. This report, put out by SEE Action, reviews state applications of DRIPE and provides example methodologies that have been used to determine DRIPE estimates. https://www4.eere.energy.gov/seeaction/system/files/documents/DRIPE-finalv3_0.pdf

Tools

The following tools can be used to assess reliability benefits from energy efficiency and renewable energy measures.

- **GE Multi-Area Reliability Simulation (GE MARS).** GE MARS enables the electric utility planner to quickly and accurately assess the reliability of a generation system that comprises any number of interconnected areas. http://www.geenergyconsulting.com/practice-area/software-products/mars
- **Avoided Cost Calculator.** Developed by E3 for use in California, this tool helps users to estimate avoided costs of their demand-side program. Avoided costs measured in this calculator include electricity generation costs, generation capacity costs, ancillary services, T&D capacity costs, environmental costs (i.e., avoided greenhouse gases), and avoided RPS costs. http://www.cpuc.ca.gov/General.aspx?id=5267

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